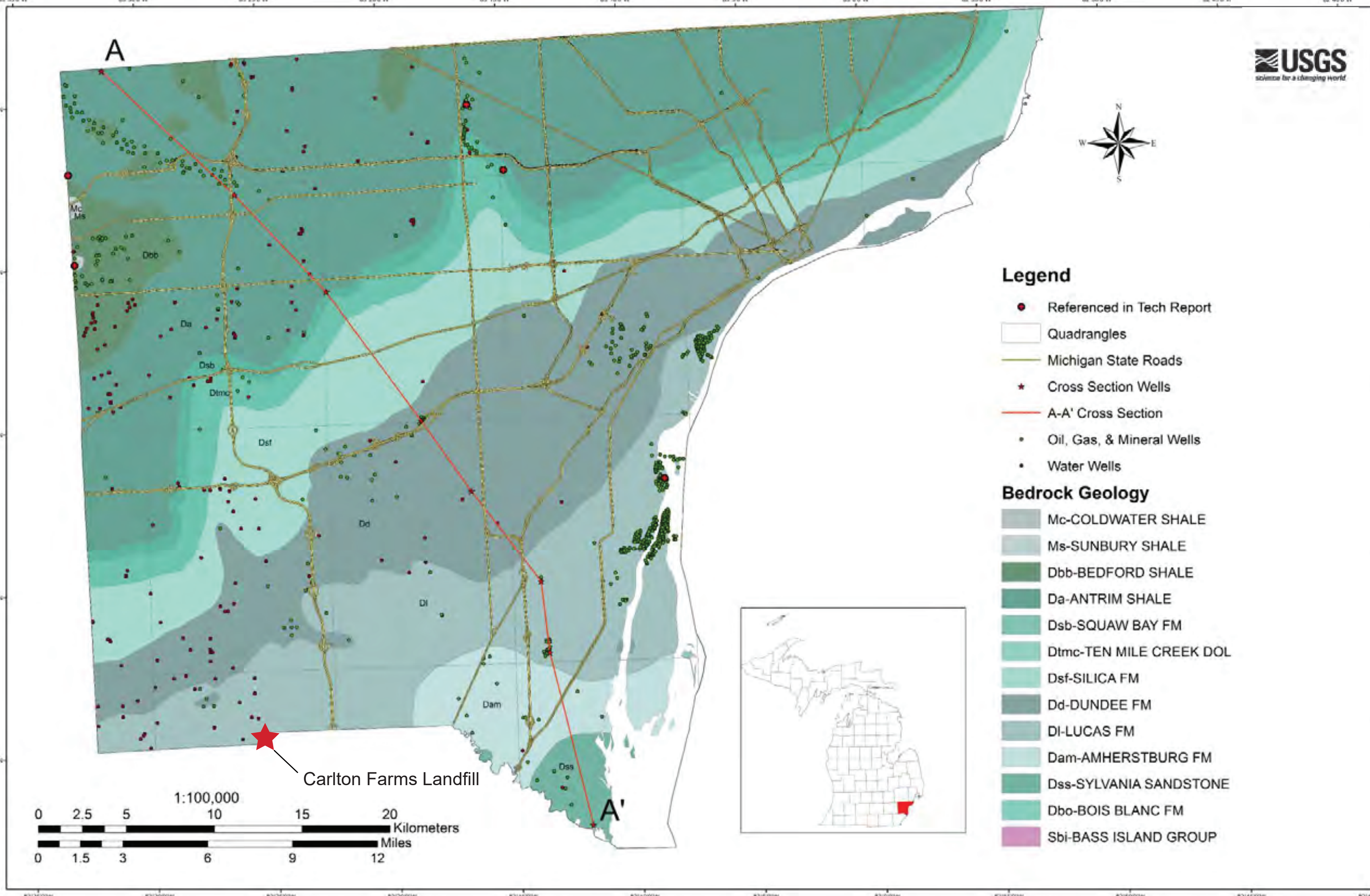

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Figure B.8-16
Bedrock Geology of
Wayne County Michigan
2019 Feasibility

Scale: NTS	Date: September 2019
2019_CFL_EGLE_Fig_B.8-16.pdf	By: WEK / Checked: CW

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(From Voice, Peter, undated, Revised Bedrock Map of Wayne County Michigan: An opportunity to Reassess the Natural Resources of Wayne County, Department of Geological and Environmental Sciences and the Michigan Geological Survey, Western Michigan University)

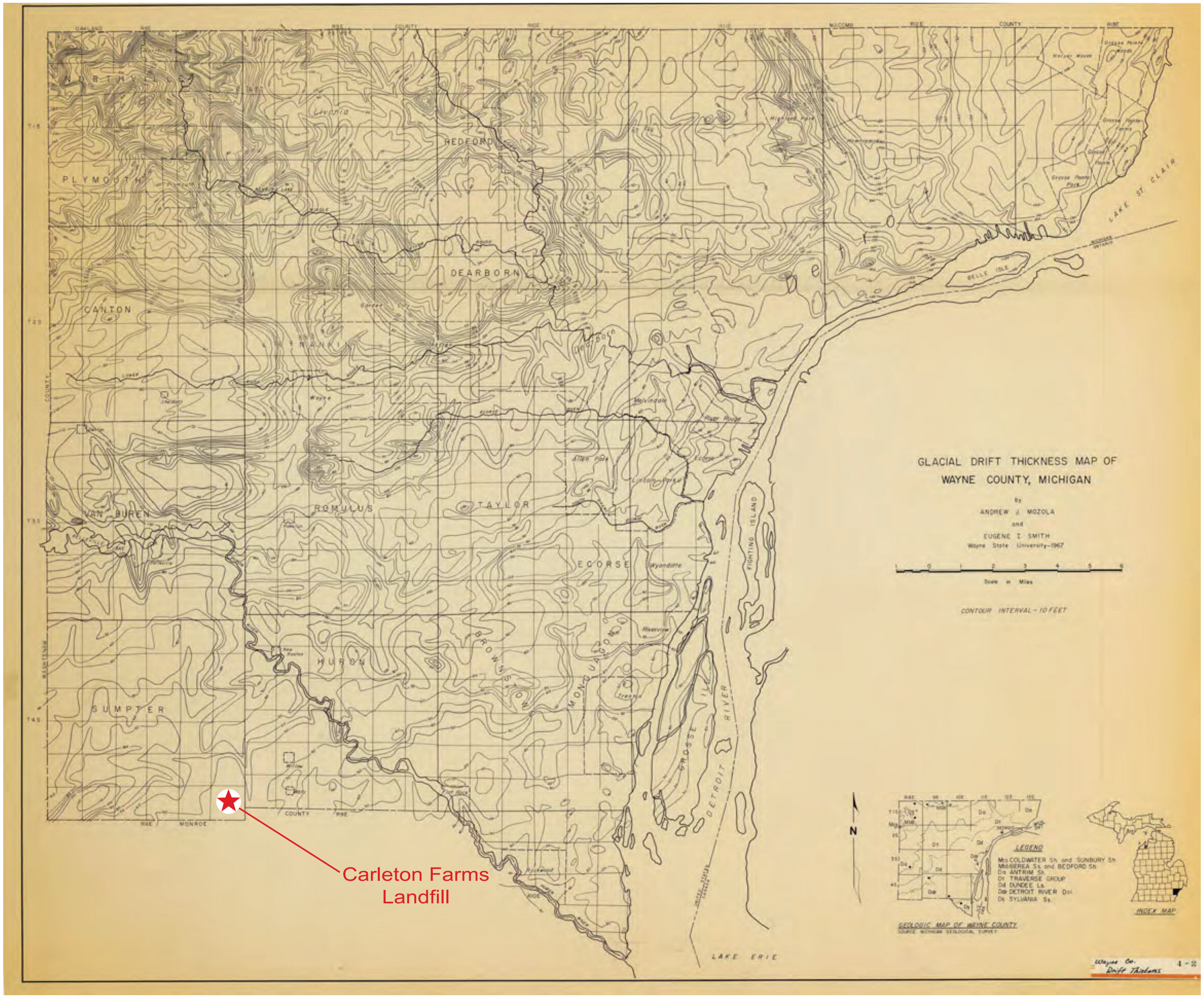

Figure B.8-17
Glacial Drift Thickness Map of
Wayne County Michigan
2019 Permit Application

Scale: NTS	Date: September 2019	
2019_CFL_EGLE_Fig_B.8-17.pdf	By: WEK	Checked: CW

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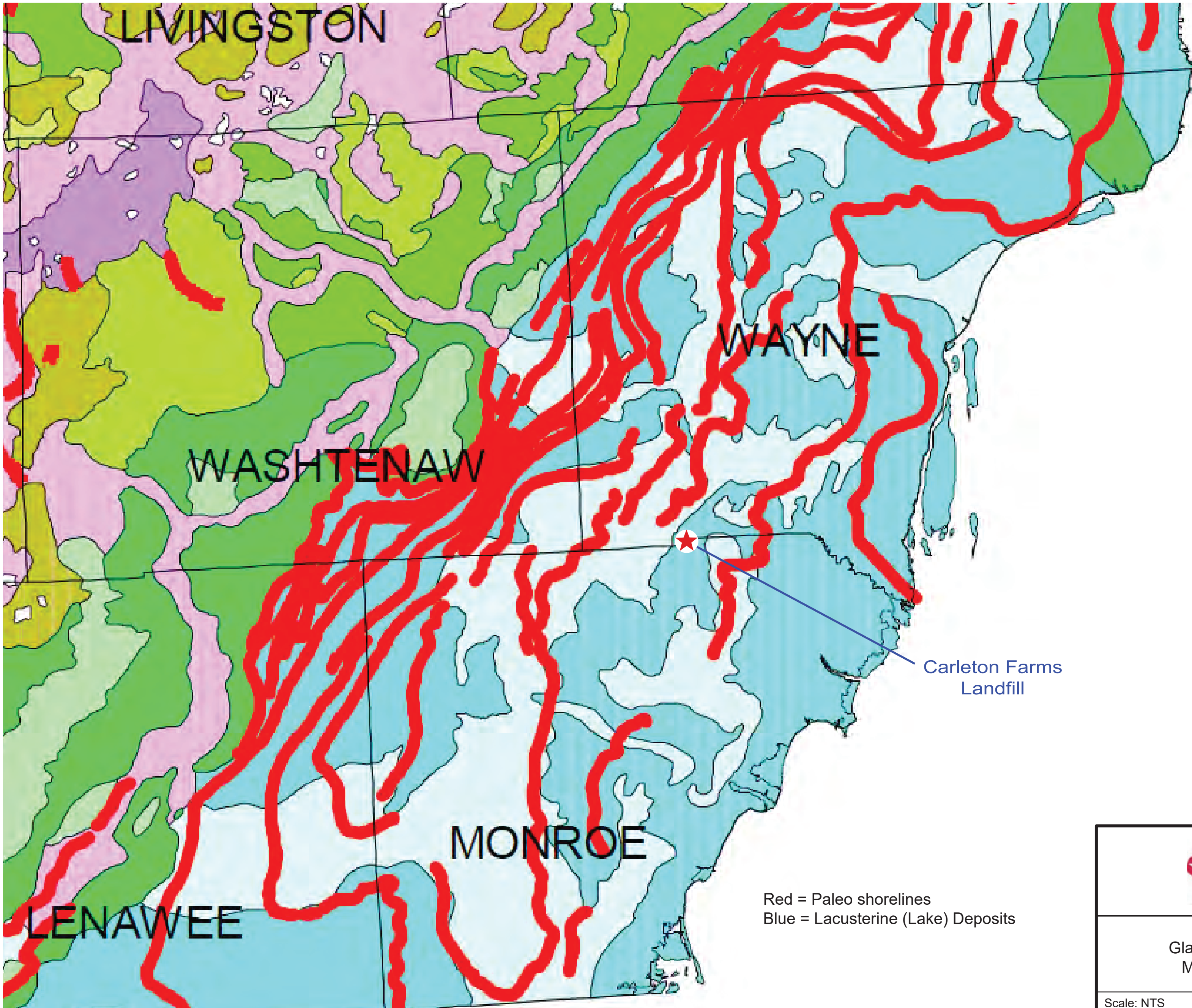

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Figure B.8-18
Glacial Geology of Wayne and Monroe Counties Michigan
2019 Permit Application

Scale: NTS	Date: September 2019	
2019_CFL_EGLE_Fig_B.8-18.pdf	By: KRS	Checked: CW

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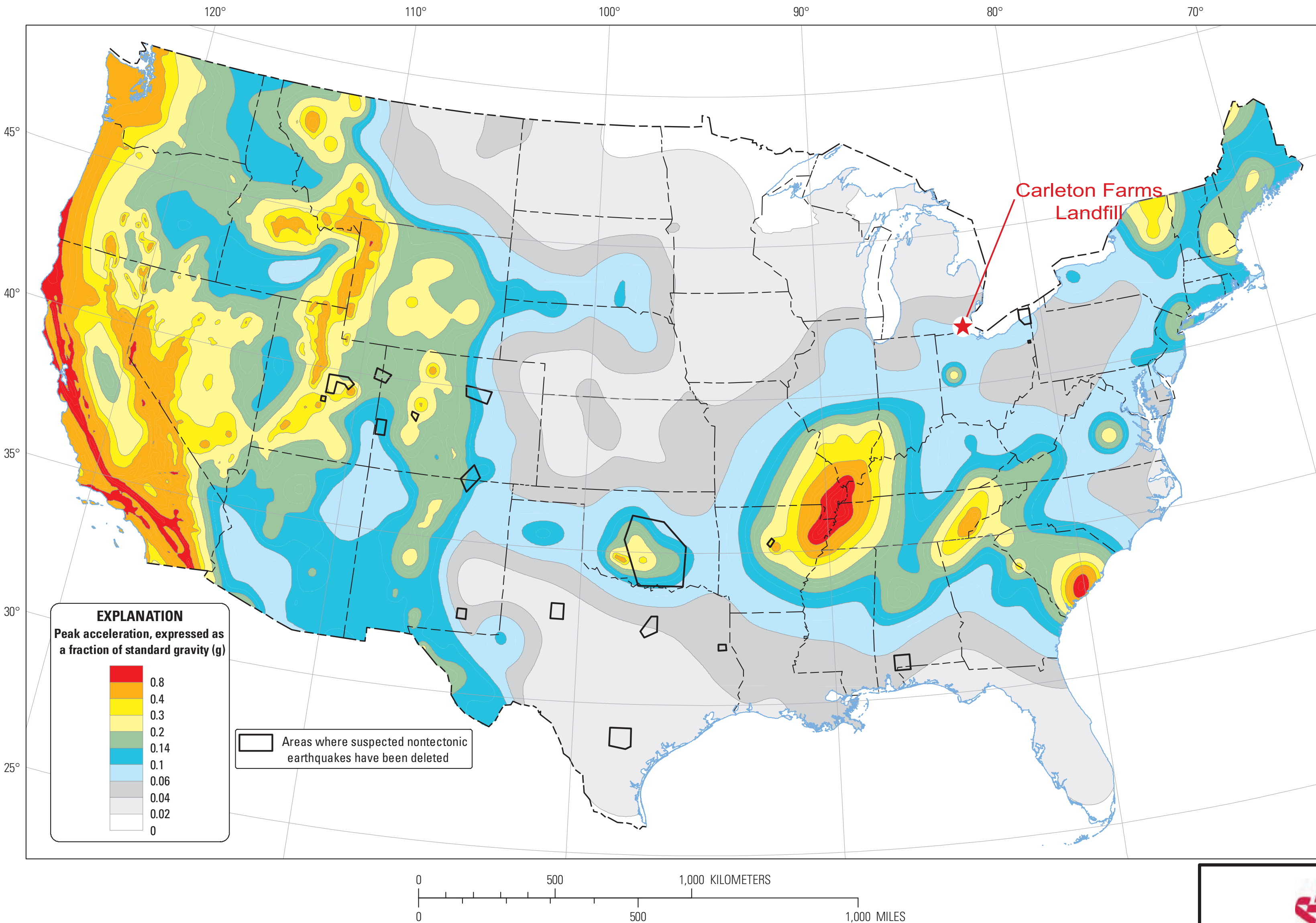
(From 1982 Quaternary Geology of Michigan, Michigan Department of Natural Resources)



Two-percent probability of exceedance in 50 years map of peak ground acceleration

(From Voice, Peter, undated, Revised Bedrock Map of Wayne County Michigan: An opportunity to Reassess the Natural Resources of Wayne County, Department of Geological and Environmental Sciences and the Michigan Geological Survey, Western Michigan University)

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Figure B.8-19
Peak Ground Acceleration,
2% Probability of Exceedance in 50 Years
2019 Feasibility

Scale: See Figure Scale	Date: September 2019
2019_CFL_EGLE_Fig_B.8-19.pdf	By: WEK / Checked: CW

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Figure B.8-20
Location of Seismic Events
in Southern Michigan, 1919-2019
2019 Permit Application

Scale: See Bar Scale	Date: September 2019	
2019_CFL_EGLE_Fig_B.8-20.pdf	By: WEK	Checked: CW

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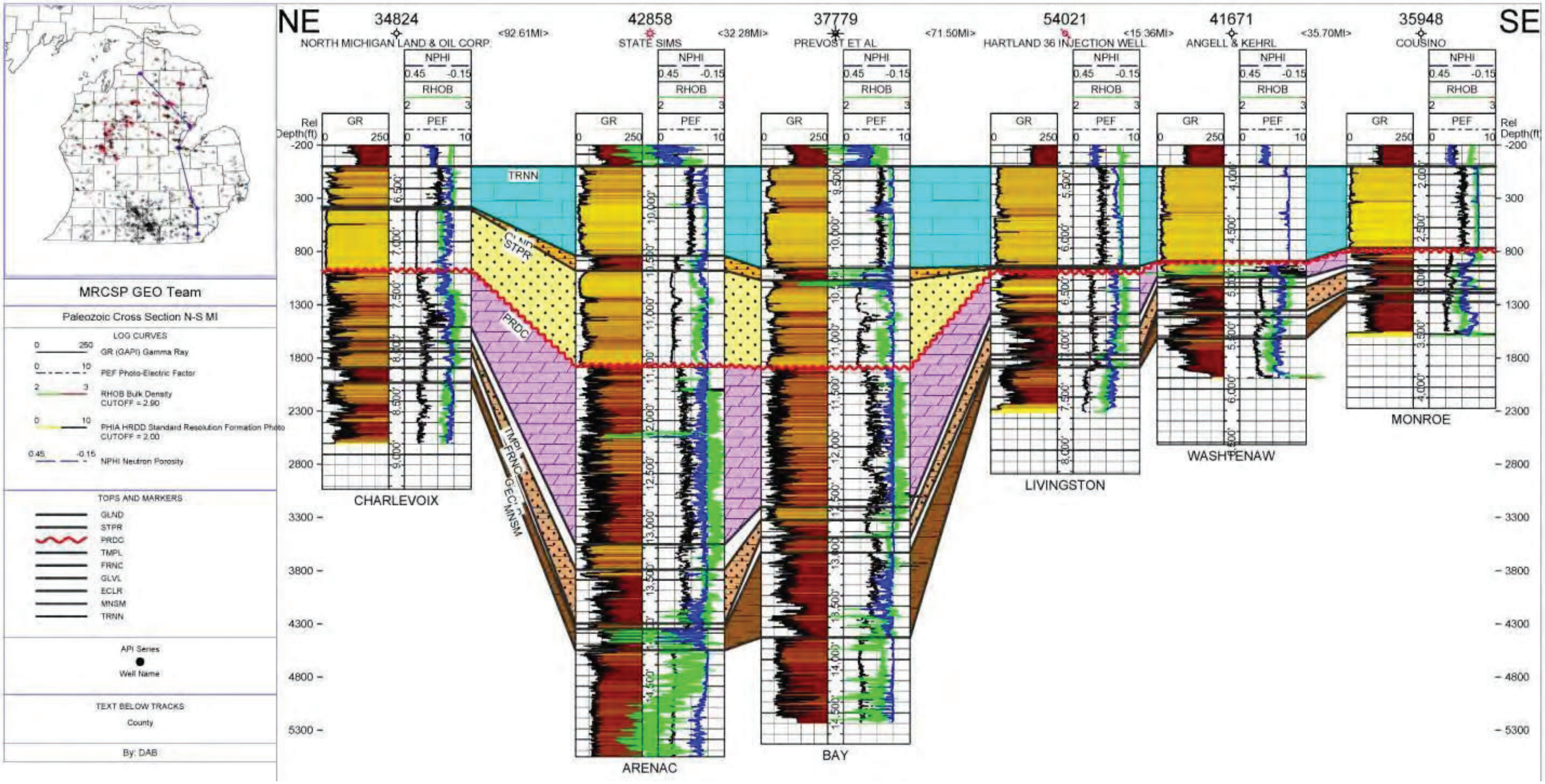

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Figure B.8-21
Local Cross Section

2019 Permit Application

Scale: NTS	Date: September 2019
2019_CFL_EGLE_Fig_B.8-21.pdf	By: WEK / Checked: CW

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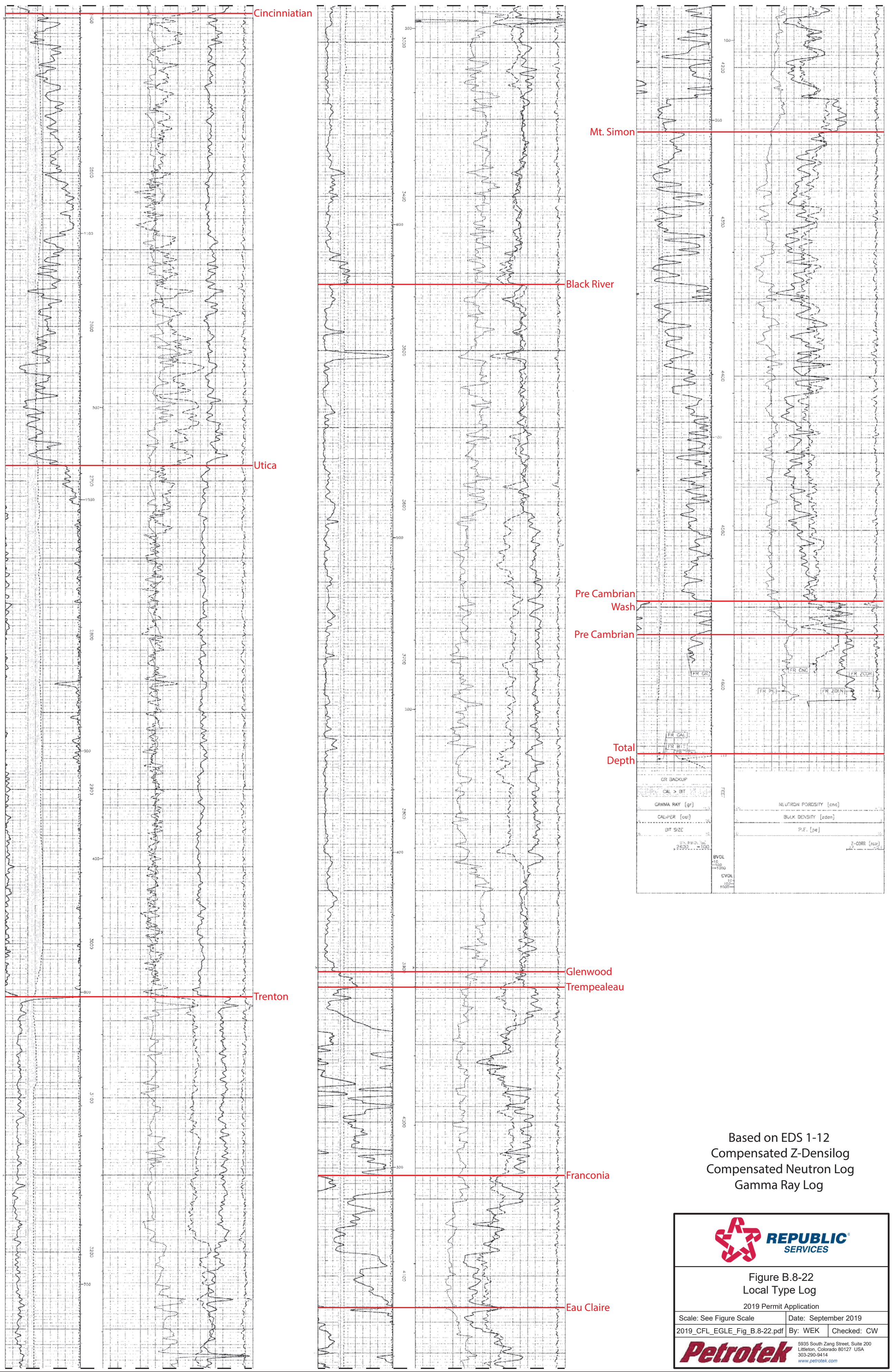

Based on EDS 1-12
Compensated Z-Densilog
Compensated Neutron Log
Gamma Ray Log

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Figure B.8-22
Local Type Log

2019 Permit Application

Scale: See Figure Scale	Date: September 2019	
2019_CFL_EGLE_Fig_B.8-22.pdf	By: WEK	Checked: CW

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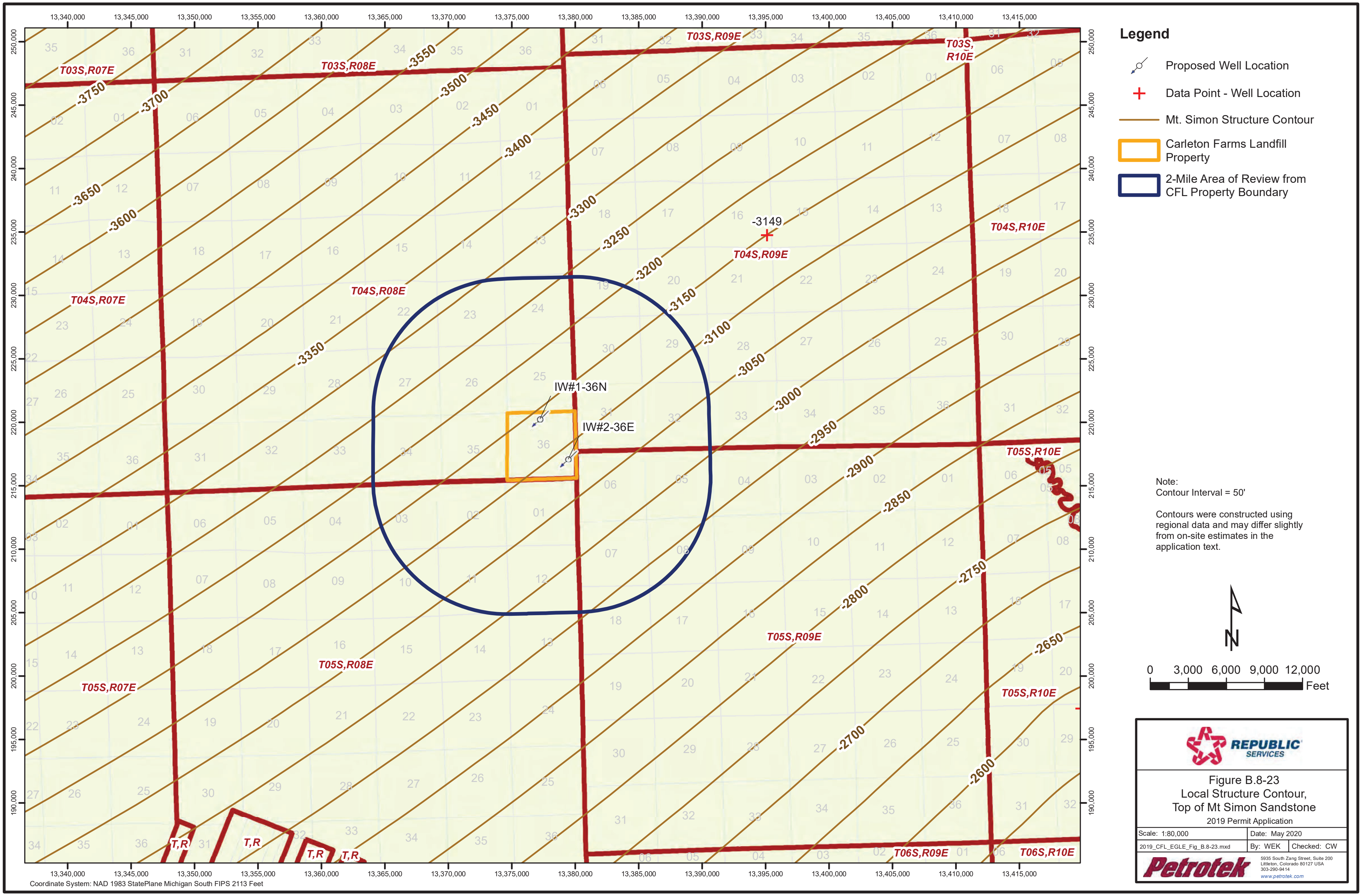
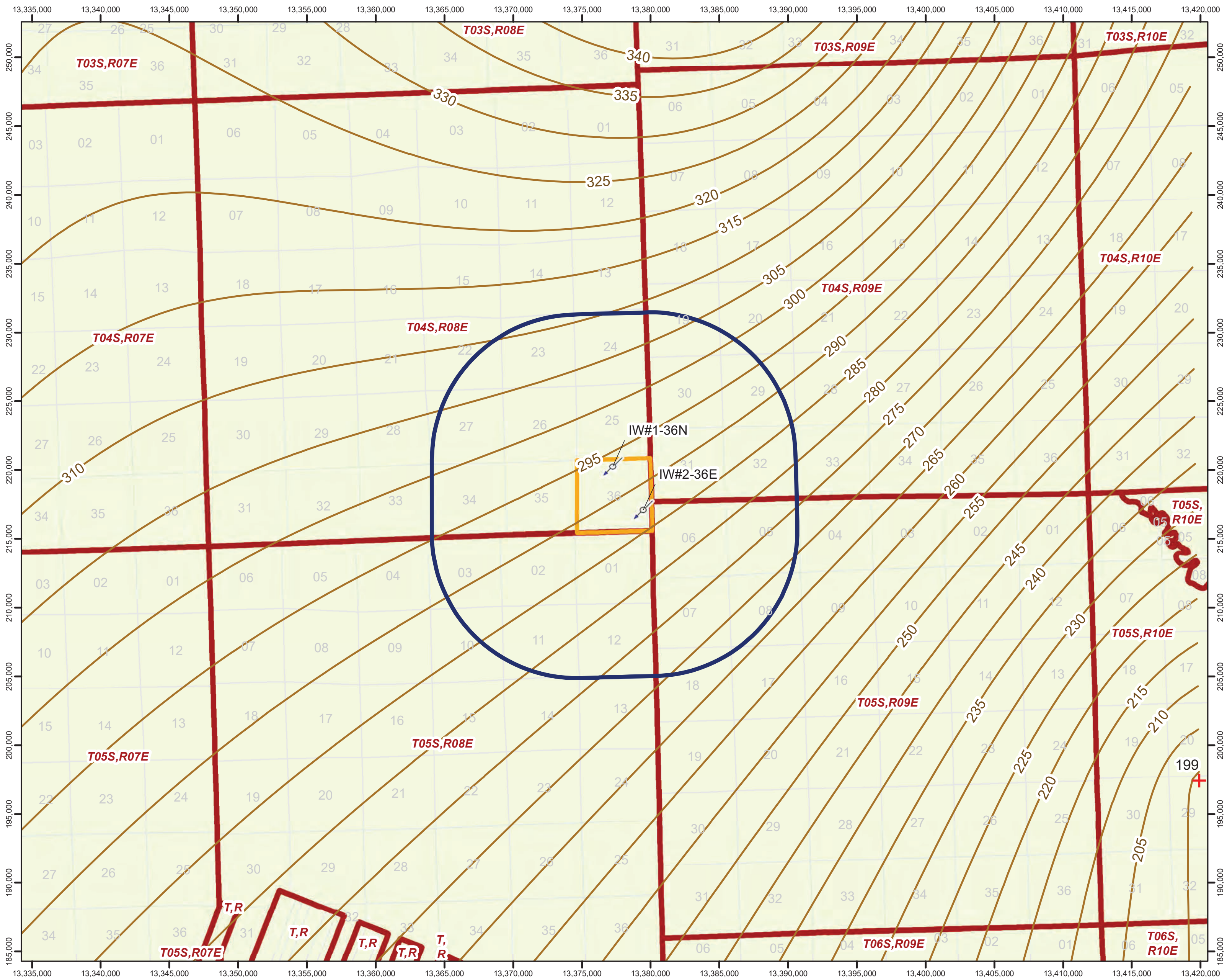


Figure B.8-23
Local Structure Contour,
Top of Mt Simon Sandstone
2019 Permit Application



Coordinate System: NAD 1983 StatePlane Michigan South FIPS 2113 Feet

Legend

- Proposed Well Location
- Data Point - Well Location
- Mt Simon Isopach Contour
- Carleton Farms Landfill Property
- 2-Mile Area of Review from CFL Property Boundary

Note:
Contour Interval = 5'

Isopach contours include thickness of Mt Simon formation and Granite Wash.

Contours were constructed using regional data and may differ slightly from on-site estimates in the application text.

0 3,000 6,000 9,000 12,000 Feet

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Figure B.8-24
Local Isopach Map,
Mt Simon Sandstone
2019 Permit Application

Scale: 1:83,000	Date: May 2020
2019_CFL_EGLE_Fig_B.8-24.mxd	By: WEK Checked: CW

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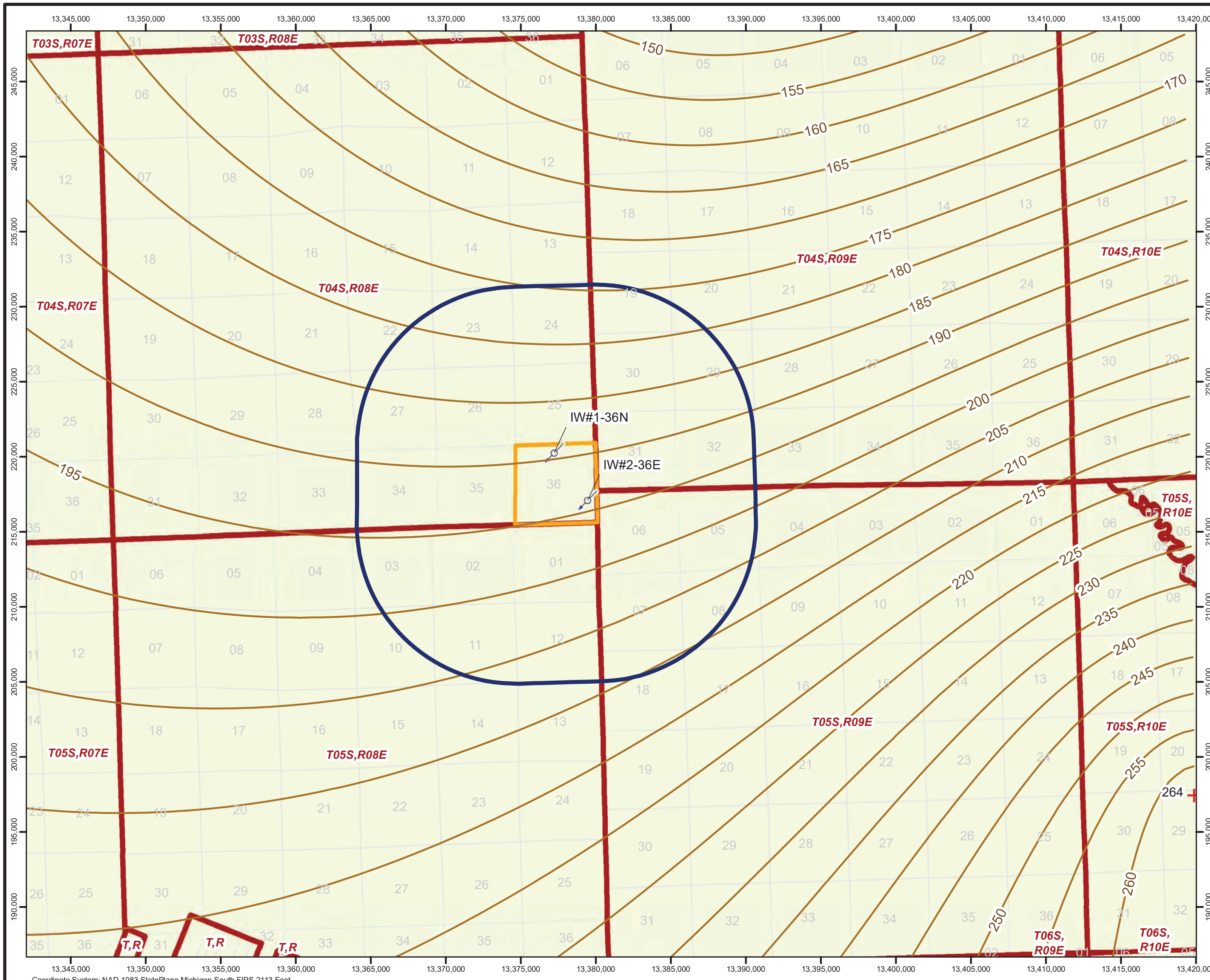

Legend

- Proposed Well Location
- Data Point - Well Location
- Eau Claire Isopach Contour
- Carleton Farms Landfill Property
- 2-Mile Area of Review from CFL Property Boundary

Note:
Contour Interval = 5'

Contours were constructed using regional data and may differ slightly from on-site estimates in the application text.

N

0 3,000 6,000 9,000 12,000 Feet

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Figure B.8-25
Local Isopach Map,
Eau Claire Formation

2019 Permit Application

Scale: 1:75,000	Date: May 2020
2019_CFL_EGLE_Fig_B.8-25.mxd	By: WEK — Checked: CW

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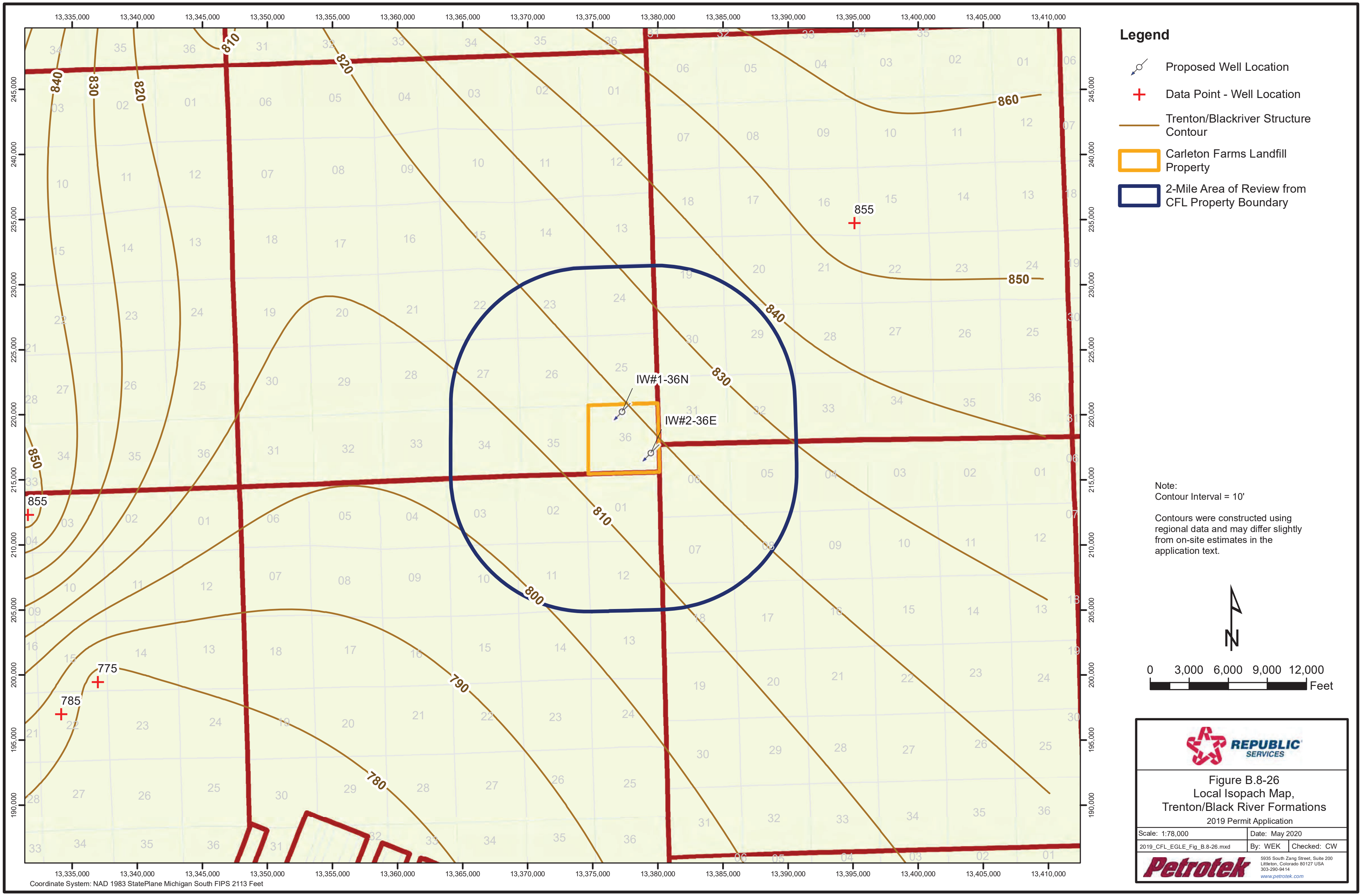
Legend
Proposed Well Location
Data Point - Well Location
Trenton/Blackriver Structure Contour
Carleton Farms Landfill Property
2-Mile Area of Review from CFL Property Boundary
IW#1-36N
IW#2-36E
Note:
Contour Interval = 10'
Contours were constructed using regional data and may differ slightly from on-site estimates in the application text.
0 3,000 6,000 9,000 12,000 Feet
N
Coordinate System: NAD 1983 StatePlane Michigan South FIPS 2113 Feet
REPUBLIC SERVICES
Figure B.8-26
Local Isopach Map,
Trenton/Black River Formations
2019 Permit Application
Scale: 1:78,000
Date: May 2020
2019_CFL_EGLE_Fig_B.8-26.mxd
By: WEK
Checked: CW
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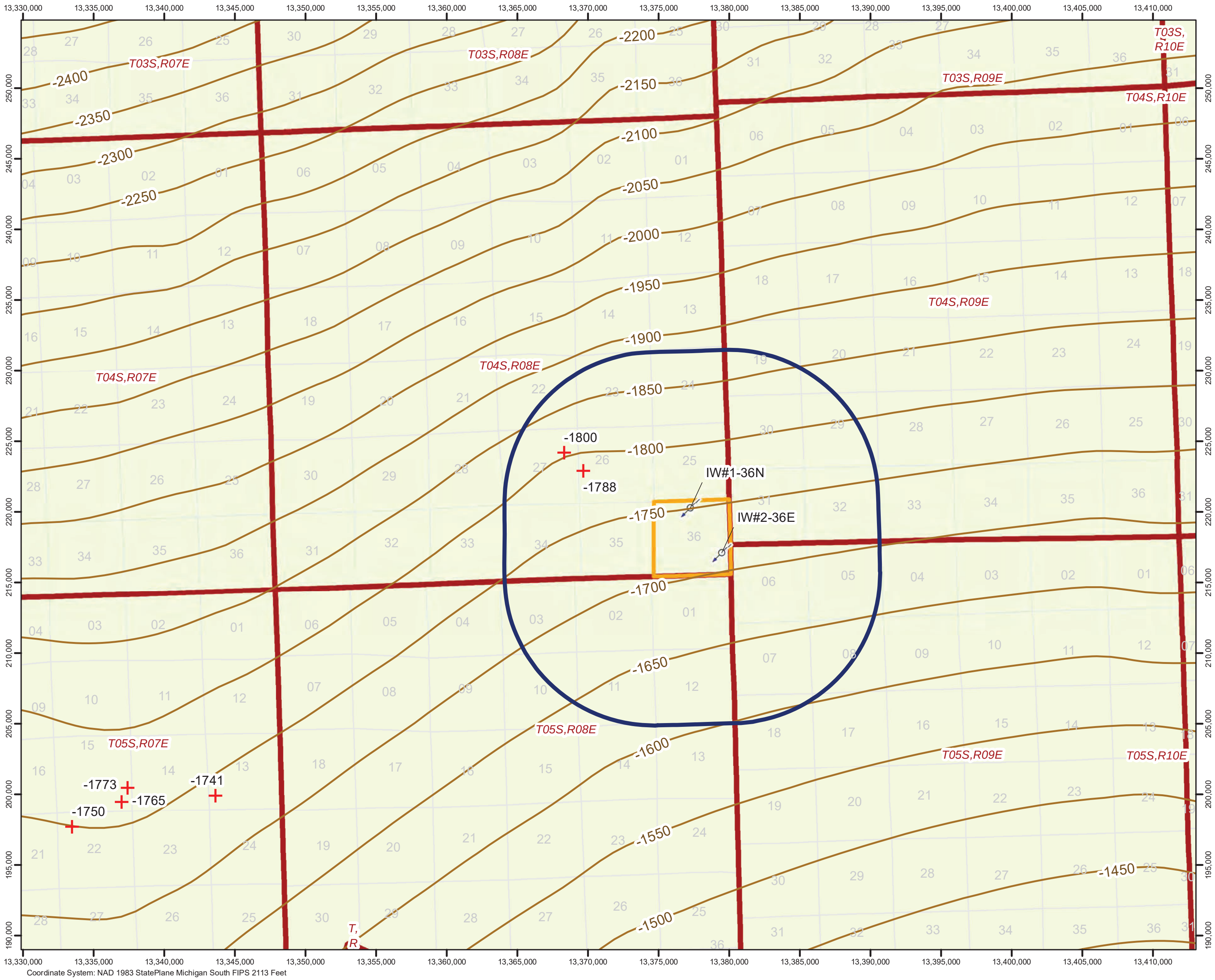

Legend

Proposed Well Location

Data Point - Well Location

Trenton/Blackriver Structure Contour

Carleton Farms Landfill Property

2-Mile Area of Review from CFL Property Boundary

Note:
Contour Interval = 50'

Contours were constructed using regional data and may differ slightly from on-site estimates in the application text.

N

0 3,000 6,000 9,000 12,000 Feet

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Figure B.8-27
Local Structure Contour,
Top of Trenton/Black River Formations
2019 Permit Application

Scale: 1:80,000	Date: May 2020
2019_CFL_EGLE_Fig_B.8-27.mxd	By: WEK Checked: CW

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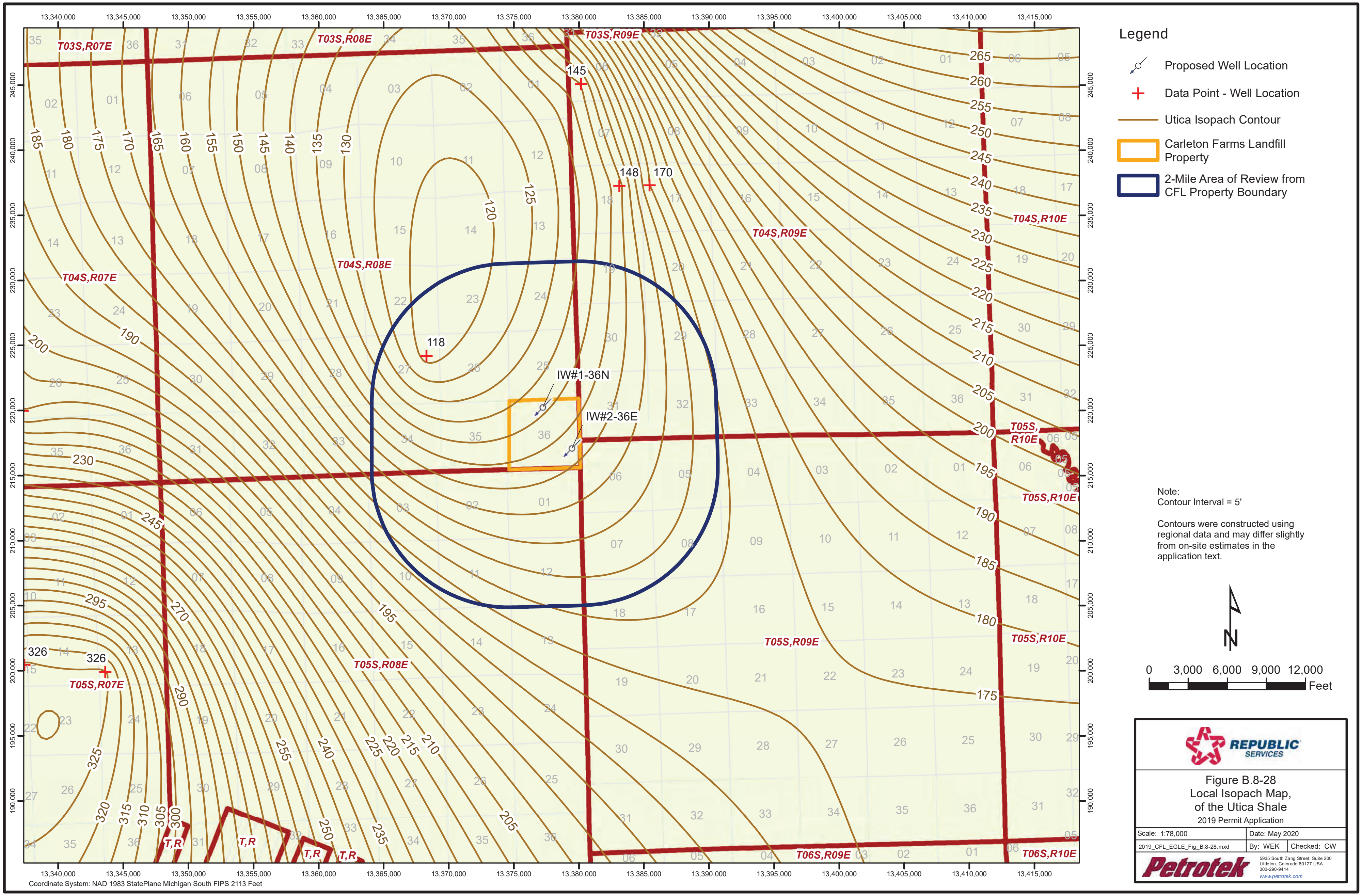

Legend
Proposed Well Location
Data Point - Well Location
Utica Isopach Contour
Carleton Farms Landfill Property
2-Mile Area of Review from CFL Property Boundary
IW#1-36N
IW#2-36E
T03S,R07E
T03S,R08E
T03S,R09E
T04S,R07E
T04S,R08E
T04S,R09E
T04S,R10E
T05S,R07E
T05S,R08E
T05S,R09E
T05S,R10E
T06S,R09E
T06S,R10E
Note:
Contour Interval = 5'
Contours were constructed using regional data and may differ slightly from on-site estimates in the application text.
0 3,000 6,000 9,000 12,000 Feet
Coordinate System: NAD 1983 StatePlane Michigan South FIPS 2113 Feet
REPUBLIC SERVICES
Figure B.8-28
Local Isopach Map, of the Utica Shale
2019 Permit Application
Scale: 1:78,000
Date: May 2020
2019_CFL_EGLE_Fig_B.8-28.mxd
By: WEK
Checked: CW
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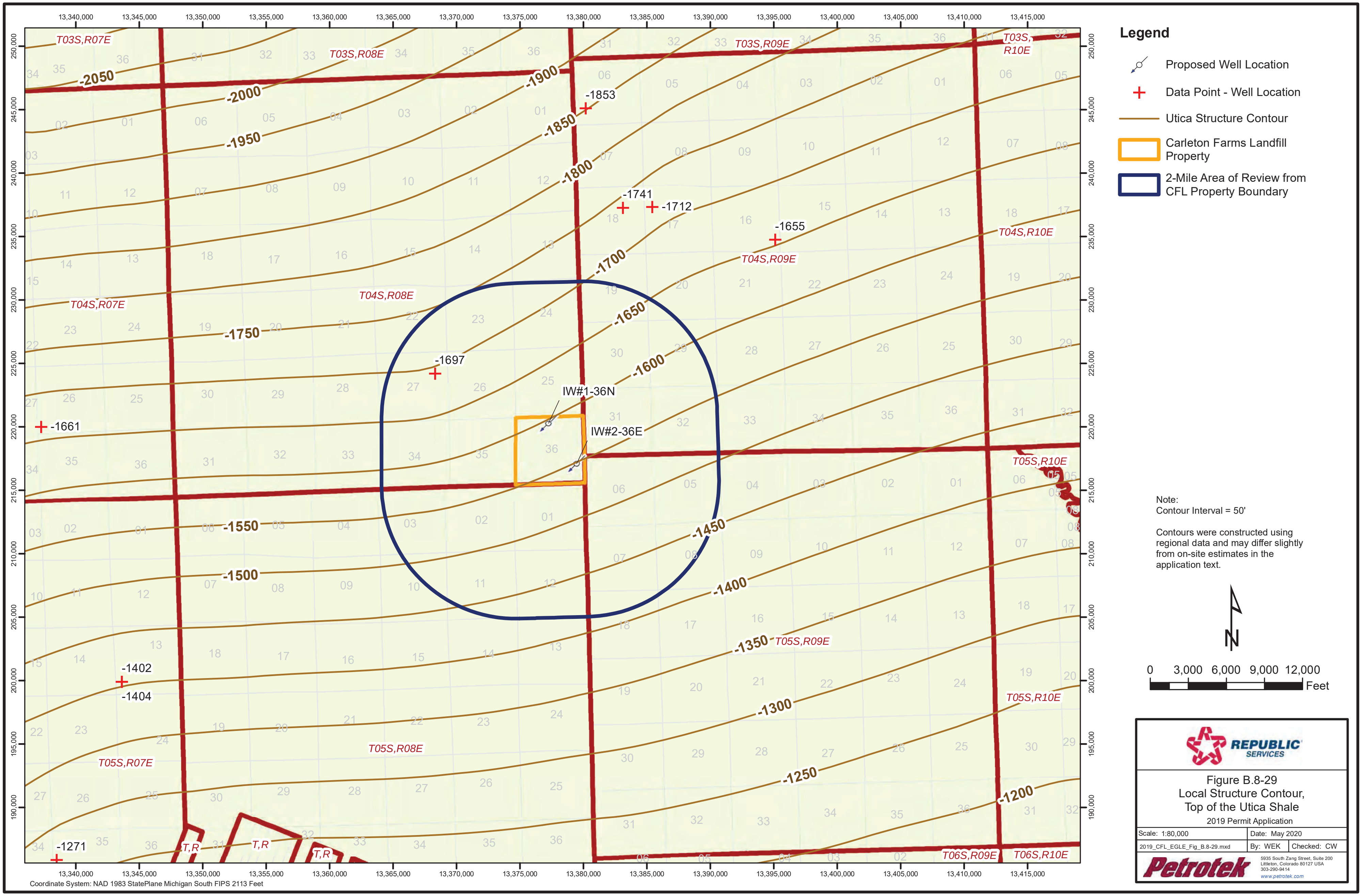
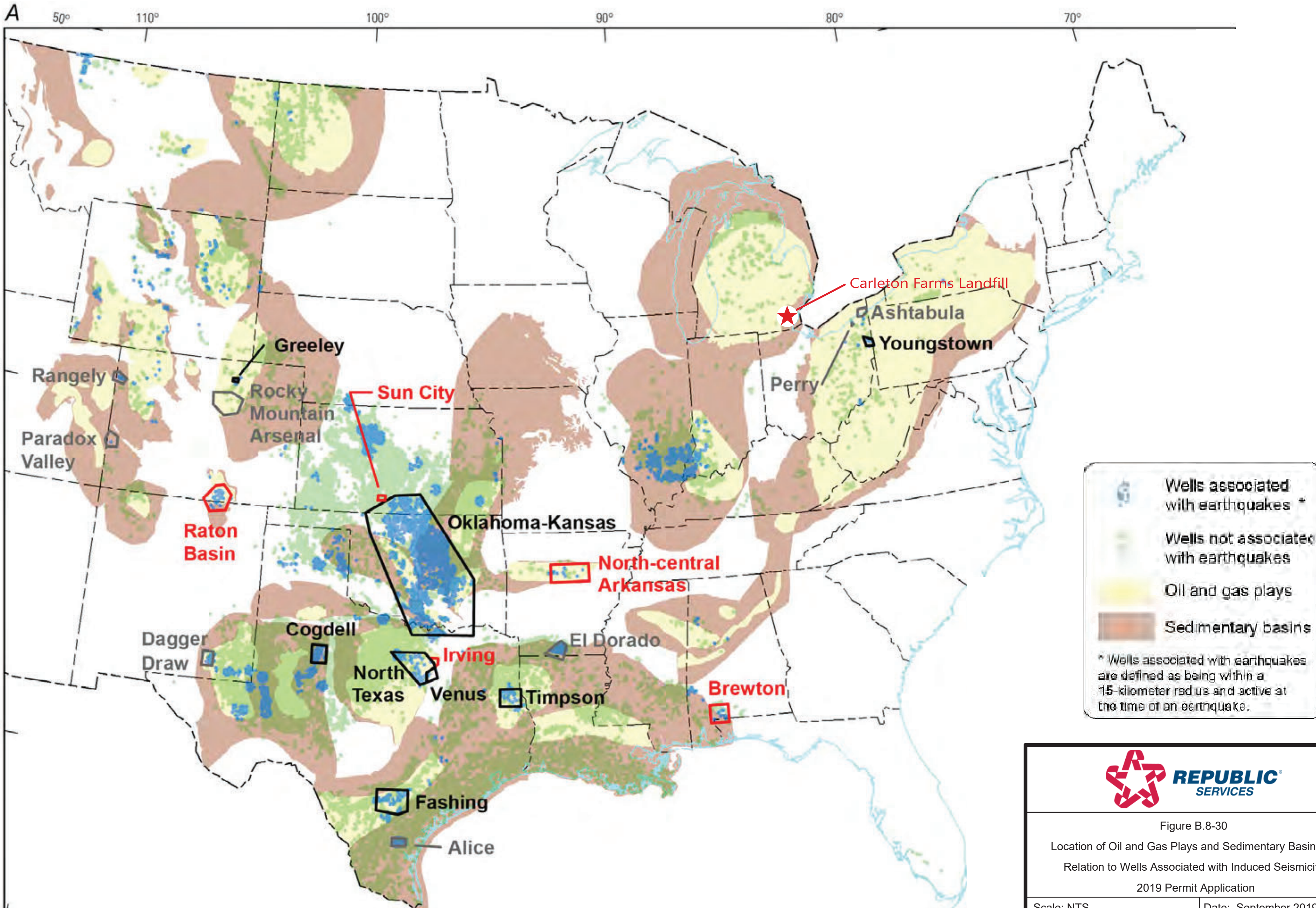


Figure B.8-29
Local Structure Contour,
Top of the Utica Shale
2019 Permit Application



(USGS, 2016)

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Figure B.8-30

Location of Oil and Gas Plays and Sedimentary Basins in Relation to Wells Associated with Induced Seismicity

2019 Permit Application

Scale: NTS	Date: September 2019
2019_CFL_EGLE_Fig_B.8-30.pdf	By: WEK / Checked: CW

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B.9 Chemical, physical and bacteriological characterizations of the waste stream before and after treatment and/or filtration. Include a characterization of the compatibility of the injectate with the injection zone and the fluid in the injection zone along with a characterization of the potential for multiple waste streams to react in the well bore or in the injection zone.

Injectate Characteristics

Carleton Farms Landfill (CFL) is an operating Type II municipal solid waste (MSW) Landfill and an MSW Incinerator Ash landfill. Wells IW#1-36N and IW#2-36E will inject non-hazardous fluids generated on-site from the leachate drainage system conveyed to the leachate storage system, wherein collection pipes from landfill cells drain leachate directly into a sump, and is pumped to either a lift station or directly to the existing above ground storage tanks. There is a 500,000 gallon storage tank near the proposed IW#1-36N location north of Cell 210 that receives leachate from MSW cells. There are two 80,000 gallon storage tanks near the proposed location for IW#2-36E well that receives leachate from the MSW as well as the Ash Cells (monofill). Leachate stored in the 500,000-gallon tank will be diverted to IW#1-36N and leachate from the two 80,000-gallon tanks will be diverted to IW#2-36E; however, wells could accept leachate from either or both tanks should either well be unavailable at any time (i.e., shut down for maintenance) or such operation is found necessary to optimize fluid disposal. Leachate received by above ground storage tanks is currently pumped to a truck loadout station for either on-site recirculation (if approved by appropriate agencies) or for off-site disposal. Historically, leachate is removed as necessary from tanks by a third-party hauler that can service the site as needed. Licensed industrial waste haulers have been used to collect and transport fluids for disposal at Clean Earth in Detroit Michigan, although other offsite non-hazardous liquid management facilities may be used.

As necessary, gas condensate, storm water, surface water run-off, and/or fluids derived from or necessary for IW#1-36N and IW#2-36E operation and maintenance may also be injected. However, fluid from the leachate collection system is anticipated to constitute the majority of the total fluid volume.

Landfill leachate is generated when precipitation contacts the solid waste in the landfill's active disposal area. As this precipitation migrates downward through the waste mass, it dissolves soluble materials (or leaches) and mixes with other liquids contained within the waste or generated as part of the degradation process. Landfill leachate is comprised of approximately water, dissolved salts, and other inorganic and organic components. Injectate will also include landfill gas condensate. Table B.9-1 presents 2017-2019 summary analytical information for select municipal solid landfill cells and the Ash monofill. As shown in this table, while analytical concentrations may vary somewhat between the landfill cells, the composition of leachate from the municipal solid waste (MSW) landfill cells and Ash monofill is relatively comparable.

Under the Carleton Farms Landfill Operating License, total leachate volume is recorded on a monthly basis and water quality on a quarterly basis. Samples are collected on a quarterly basis, and analyzed for the parameters per the Landfill Operating License requirements.

Compatibility and plugging problems encountered due to injection of non-hazardous landfill leachate and gas condensate are possible due to particulate matter, which could cause decreased flow capacity. Screens or filters may be used to condition fluids if needed. Due to the composition of the fluid to be injected and landfill origin, periodic biocide treatments may be instituted as needed to prevent the establishment of bacterial plugging issues. Also, the possibility of inorganic precipitate within tubing, pipe, or the injection formation could require monitoring, so implementation of a system to prevent plugging or treat leachate may be required. Such solids, compatibility, or bacterial problems, if they do occur, would not be a containment issue, but would be an operations issue. If plugging occurred and was not remedied, the operator could reduce injection rates so that maximum pressure limits are not exceeded. To sustain rates if such a situation develops, periodic stimulations may be required, but would be accomplished within regulatory requirements.

Table B.9-1. Leachate Chemical Characterization, Carleton Farms Landfill

Parameter		Composite MSW Cells			Ash Monofill		
		Max	Min	Average	Max	Min	Average
TEMPERATURE, FIELD (C)		22.6	5.8	16.2	24.2	12.1	18.9
Potassium (mg/L)	7440-09-7	9900	127	5883	2990	261	1387
Barium (mg/L)	7440-39-3	20.8	0.112	7.8	2.56	0.288	0.94
Nitrogen, Ammonia (mg/L)	7664-41-7	1820	1.4	324	2180	323	1530
Nitrogen, Total Inorganic (mg/L)	SAN-005	1820	2.2	324	2180	323	1530
Antimony (mg/L)	7440-36-0	0.0198	0.0058	0.011	0.0272	0.0114	0.0207
Arsenic (mg/L)	7440-38-2	0.109	0.02	0.07	0.265	0.228	0.25
Beryllium (mg/L)	7440-41-7	<0.005	<0.001	0.004	<0.05	<0.005	0.02
Cadmium (mg/L)	7440-43-9	<0.001	0.00082	0.001	<0.0077	0.0043	0.0055
Chromium (mg/L)	7440-47-3	0.0385	<0.005	0.017	0.518	<0.456	0.487
Cobalt (mg/L)	7440-48-4	<0.05	0.0132	0.026	0.0513	0.036	0.044
Copper (mg/L)	7440-50-8	0.0319	0.0119	0.0195	0.0108	0.0069	0.0085
Iron (mg/L)	7439-89-6	61.6	4.23	24.6	21.7	5.14	11.1
Lead (mg/L)	7439-92-1	<0.005	0.0027	0.004	0.0125	0.0065	0.0093
Nickel (mg/L)	7440-02-0	0.113	0.0625	0.089	0.481	0.436	452
Selenium (mg/L)	7782-49-2	0.0111	0.0067	0.0091	0.0115	0.0073	0.0097
Silver (mg/L)	7440-22-4	<0.001	<0.0002	0.001	0.0015	<0.001	0.001
Thallium (mg/L)	7440-28-0	<0.01	<0.004	0.01	<0.01	<0.01	0.01
Vanadium (mg/L)	7440-62-2	0.0192	<0.01	0.013	0.219	0.197	0.212
Zinc (mg/L)	7440-66-6	<0.1	0.0528	0.0843	0.371	0.048	0.173
Bromodichloromethane (ug/L)	75-27-4	<10*	<1	2	<25*	<1	11
Bromoform (ug/L)	75-25-2	<10*	<1	2	<25*	<1	11
Carbon Tetrachloride (ug/L)	56-23-5	<10*	<1	2	<25*	<1	11
Chlorobenzene (ug/L)	108-90-7	<10*	<1	2	<25*	<1	11
Chloroethane (ug/L)	75-00-3	<50*	<5	12	<125*	<5	53

Parameter		Composite MSW Cells			Ash Monofill		
		Max	Min	Average	Max	Min	Average
Manganese (mg/L)	7439-96-5	2.15	0.31	1.35	2.63	0.155	0.98
Magnesium (mg/L)	7439-95-4	24.8	<5	13.9	144	84	105
Mercury (mg/L)	7439-97-6	n/a	n/a	n/a	n/a	n/a	n/a
Sodium (mg/L)	7440-23-5	18300	11300	15000	4760	4040	4493
Bicarbonate Alkalinity (mg/L)	71-52-3	4800	320	2073	12000	9000	10900
Carbonate Alkalinity (mg/L)	SAN-001	<10*	<10	10	<10	<10	10
Phenolics (mg/L)	64743-03-9	3.6	1.4	2.3	7.7	0.386	4
TDS (mg/L)	SAN-006	106000	2940	64171	19900	18200	19300
Sulfate (mg/L)	14808-79-8	<587	<0.25	142	310	25.6	125
COD (mg/L)	SAN-008	6130	3800	5040	12600	7320	9890
NITROGEN, NITRATE-NITRITE (MG/L)	SAN-004	0.8	<0.04	0.3	2.2	0.2	0.8
PHOSPHORUS, TOTAL (MG/L)	7723-14-0	14.4	14.4	14.4	13.4	13.4	13.4
TOC (MG/L)	7440-44-0	1940	5.2	588	4120	351	2364
Conductivity (UMHOS/CM)	10-34-4	45300	1326	16391	18910	1299	11730
Boron (MG/L)	7440-42-8	47	0.187	7	47	38.7	44
CYANIDE, TOTAL (MG/L)	57-12-5	0.007	<0.005	0.006	0.14	0.028	0.07
ETHYLBENZENE (UG/L)	100-41-4	<14.1*	<1	5	<25	6.8	13
CHLORIDE (MG/L)	n/a	99400	1020	46656	31700	1240	9709
CHLOROMETHANE (UG/L)	74-87-3	<50*	<5	12	<125*	5	53
DIETHYL ETHER [ETHYL ETHER] (UG/L)	60-29-7	<50*	<5	16	<50*	25	42
TETRAHYDROFURAN (UG/L)	109-99-9	403	<12.5	114.2	1880	107	1063
Fluoride (ug/L)	n/a	<100000*	<1000	15244	n/a	n/a	n/a
Chloroform (ug/L)	67-66-3	<10*	<1	2	<25*	<1	11
Dibromochloromethane (ug/L)	124-48-1	<10*	<1	2	<25*	<1	11
1,2-Dichlorobenzene (ug/L)	95-50-1	<10*	<1	2	<25*	<1	11
1,4-Dichlorobenzene (ug/L)	106-46-7	<10*	<1	2	<25*	3.4	11
1,1-Dichloroethane (ug/L)	75-34-3	<10*	<1	2	<25*	<1	11
1,2-Dichloroethane (ug/L)	107-06-2	<10*	<1	2	<25*	<1	11
1,1-Dichloroethene (ug/L)	75-35-4	<10*	<1	2	<25*	<1	11
cis-1,2-Dichloroethene (ug/L)	156-59-2	<10*	<1	2	<25*	1.2	11
trans-1,2-Dichloroethene (ug/L)	156-60-5	<10*	<1	2	<25*	<1	11
1,2-Dichloropropane (ug/L)	78-87-5	<10*	<1	2	<25*	<1	11
cis-1,3-Dichloropropene (ug/L)	10061-01-5	<10*	<1	2	<25*	<1	11
trans-1,3-Dichloropropene (ug/L)	10061-02-6	<10*	<1	2.4	<25*	<1	11
Bromomethane (ug/L)	74-83-9	<50	<1	11	<125*	<5	53
Dibromomethane (ug/L)	74-95-3	<10*	<1	2	<25*	<1	11
Methylene Chloride (ug/L)	75-09-2	<50	<1	11	<25*	<5	53
Iodomethane (ug/L)	74-88-4	<10*	<1	3	<25*	<1	11
1,1,1,2-Tetrachloroethane (ug/L)	630-20-6	<10*	<1	2	<25*	<1	11
1,1,2,2-Tetrachloroethane (ug/L)	79-34-5	<10*	<1	2	<25*	<1	11

Parameter		Composite MSW Cells			Ash Monofill		
		Max	Min	Average	Max	Min	Average
Tetrachloroethene (ug/L)	127-18-4	<10*	<1	2	<25*	<1	11
1,1,1-Trichloroethane (ug/L)	71-55-6	<10*	<1	2	<25*	<1	11
1,1,2-Trichloroethane (ug/L)	79-00-5	<10*	<1	2	<25*	<1	11
Trichloroethene (ug/L)	79-01-6	<10*	<1	2	<25*	<1	11
Trichlorofluoromethane (ug/L)	75-69-4	<10*	<1	2	<25*	<1	11
1,2,3-Trichloropropane (ug/L)	96-18-4	<10*	<1	2	<25*	<1	11
Vinyl chloride (ug/L)	75-01-4	<10*	<1	2	<25*	<1	11
Benzene (ug/L)	71-43-2	<10*	<1	3	<25*	<4	11
Styrene (ug/L)	100-42-5	<10*	<1	2	<25*	<1	11
Toluene (ug/L)	108-88-3	18.7	<1	7.4	61.8	10.3	23.7
Acetone (ug/L)	67-64-1	10200	574	3445	12200	3650	8817
Acrylonitrile (ug/L)	107-13-1	<50*	<5	16	<50*	<25*	42
Bromochloromethane (ug/L)	74-97-5	<10*	<1*	3	<10*	<5*	8
Carbon disulfide (ug/L)	75-15-0	<10*	<1*	3	<10*	<5*	8
1,2-Dibromo-3-chloropropane (ug/L)	96-12-8	<50*	<5	16	<50*	<25*	42
1,2-Dibromoethane (ug/L)	106-93-4	<10*	<1*	3	<10*	<5*	8
Trans-1,4-Dichloro-2-butene (ug/L)	110-57-6	<50*	<5	16	<50*	<25*	42
2-Hexanone (ug/L)	591-78-6	<50*	<5	23	<236*	33.4	106
Calcium (mg/L)	7440-70-2	9240	31	4969	442	74.2	221
2-Butanone [MEK] (ug/L)	n/a	5240	55.1	2648	7110	7110	7110
4-Methyl-2-pentanone [MIBK] (ug/L)	n/a	91.7	<5	54.8	108	90.6	99
BOD, [5-Day] (mg/L)	n/a	3880	1150	1883	7410	206	2272
pH, Field (S.U.)	n/a	9.72	5.94	7.82	8.65	7.13	7.92
XYLENES, TOTAL (ug/L)	1330-20-7	<40.7*	<2	13.6	<50*	<20	31.1
METHYL ISOBUTYL KETONE (ug/L)	108-10-1	<50*	<50*	50	<50*	<50*	50
strontium (ug/L)	7440-24-6	57800	57800	57800	2270	2270	2270
Silica (ug/L)	n/a	24700	24700	24700	32000	32000	32000
Alkalinity, Total (ug/L)	n/a	1100000	1100000	1100000	11700000	11700000	11700000
2-BUTANONE [MEK], TCLP (UG/L)	n/a	651	306	479	5360	1620	3490
*Elevated detection limit due to sample dilution							

B.10 Information to characterize the proposed injection zone, including:

A. **The geological name of the stratum or strata making up the injection zone and the top and bottom depths of the injection zone.**
B. **An isopach map showing thickness and areal extent of the injection zone**
C. **Lithology, grain mineralogy and matrix cementing of the injection zone.**
D. **Effective porosity of the injection zone including the method of determination.**
E. **Vertical and horizontal permeability of the injection zone and the method used to determine permeability. Horizontal and vertical variations in permeability expected within the area of influence.**
F. **The occurrence and extent of natural fractures and/or solution features within the area of influence.**
G. **Chemical and physical characteristics of the fluids contained in the injection zone and fluid saturations.**
H. **The anticipated bottom hole temperature and pressure of the injection zone and whether these quantities have been affected by past fluid injection or withdrawal.**
I. **Formation fracture pressure, the method used to determine fracture pressure and the expected direction of fracture propagation.**
J. **The vertical distance between the top of the injection zone from the base of the lowest fresh water strata.**
K. **Other information the applicant believes will characterize the injection zone.**

Items A-C are detailed in Section B.8. Items D-K will be verified during drilling and testing of IW-1. Literature data available to characterize formations has been cited in previous sections. Available data are summarized below.

A. The geological name of the stratum or strata making up the injection zone and the top and bottom depths of the injection zone.

The proposed injection zone includes the interval from (deepest to shallowest) the Mt. Simon Sandstone to the Glenwood Formation. CFL intends to complete the Franconia/Dresbach through the Mt. Simon Formation, which represents the injection interval. The table below provides estimated top/bottom depths in feet below ground level (BGL) for this interval at each proposed injection well.

Estimated Formation Tops at the Proposed CFL Well Locations

Formation	Est. Depth to Top, from GL (ft)* IW#1-36N	Est. Depth to Top, from GL (ft)* IW#2-36E
Ground Level (feet ASL)	627	623
Base of Alluvium/Glacial Material	53	30
Lucas Formation (Detroit River Group)	53	30
Sylvania Sandstone	135	110
Bois Blanc	258	233
Bass Island Group	400	375
Salina Group	650	625
Niagara Group	1,122	1,097
Clinton Group	1,346	1,321
Undifferentiated Upper Cincinnatian	1,652	1,627
Utica Shale	2,227**	2,198**
Trenton Formation	2,357	2,323
Black River Formation	2,765	2,740
Glenwood	3,171	3,141
Trempealeau Formation	3,181	3,151
Franconia/Dresbach Formation	3,281	3,251
Eau Claire Formation	3,366	3,336
Mt. Simon Sandstone	3,527	3,502
Precambrian Granite Wash	3,807	3,782
Precambrian basement	3,827	3,802

*Estimated depth at proposed IW-1 location; IW-2 will likely be shallower. All depths shall be determined and finalized during well installation.

** Utica top based on regional map information. Note that often the top is picked higher up the column into the Upper Cincinnatian, resulting in a thicker Utica shale unit.

B. An isopach map showing thickness and areal extent of the injection zone

Figures B.8-7 and B.8-24 are regional and local isopach maps of the Mt. Simon Sandstone, respectively. Figures B.8-9 and B.8-25 are regional and local isopachs of the Eau Claire, respectively. Figures B.8-11a and B.8-11b are regional isopaches of the Galesville/Dresbach and Franconia Formations, respectively. Figure B.8-33 presents a local isopach of the Franconia Formation. Figures B.8-12 is a regional isopach of the Trempeleau Formation. In total, the injection zone from the base of the Mt. Simon to the base of the Black River is laterally pervasive and is approximately 650 feet thick in the CFL area.

It is noted that CFL only intends to use the Franconia/Dresbach through the Mt. Simon injection interval as an open hole completion for the proposed injection wells.

C. Lithology, grain mineralogy and matrix cementing of the injection zone.

See Section B.8 for detailed lithologic information concerning the Injection Zone formations.

D. Effective porosity of the injection zone including the method of determination.

See Section B.8 for detailed information concerning the effective porosity of the injection zone formations and method of determination. Core data available for the formations in the injection zone are presented in Section B.8.

The injection zone includes the Mt. Simon, Eau Claire, Franconia/Dresbach, Trempealeau, and Glenwood Formations. The Franconia/Dresbach to the Mt. Simon is the injection interval that will be completed, open hole, and into which injection will take place. The overlying formations constitute the remainder of the injection zone, and these formations offer arrestment capabilities. The following summarizes porosity information pertaining to the Formations of the Munsing Group and Trempealeau Formation, noting that the Mt. Simon information is also included in Section B.8.

Injection Zone: Mt. Simon Porosity Range

As indicated in Section B.8.2.2.2, the Mt. Simon injection interval is well characterized by local core data that present local porosity information. Cores were taken from the Mt. Simon at the nearby EDS well No. 2-12 from 4127-4148 ft and 4245-4258 ft. Mt. Simon porosity information obtained from theses core indicate that porosity averaged 4.8 and 10.4%, respectively, with maximum porosity within the lower interval of 13.7%, nothing that the lower (deeper) core is more representative of the Mt. Simon.

Injection Zone: Eau Claire, Franconia/Dresbach, and Trempealeau Formations Porosity Ranges

The following information addressed porosity of formations above the Mt. Simon within the Injection Zone.

Eau Claire Porosity Range: The Eau Claire was cored in the EDS #1-12 and EDS #2-12 wells (see Section B.8.2.2.2). Summary results of core analyses for the Eau Claire are presented in Tables B.8-6a and B.8-6b. Note that well EDS #1-12 is a directional well, therefore the core depths are not consistent with corrected formation tops at EDS #2-12. These data show that the sampled portion of the upper Eau Claire in EDS #1-12 exhibits a porosity ranging from 1.2-3.9%, with an average permeability K_{air} of 0.10 md. The lower portion of the Eau Clair at EDS #1-12 exhibits a porosity ranging from 5.4% to 20.7%, with an average permeability of 13.3 md. The upper Eau Claire core is described as a dolomite with laminar bedding and slight anhydrite; the lower Eau Claire core is described as a fine to medium grained sandstone.

Additional information from core data is presented in Section B.8 in Tables B.8.6a and B.8.6b.

Franconia/Dresbach Porosity Range: The Franconia and Dresbach/Galesville are considered together. Wireline data from the EDS #1-12 well indicates this general interval exhibits neutron porosity varying from 9-14%, while the same interval at the EDS #1-20 well in T3S R9E Section 20 exhibited up to 15% neutron porosity over the total interval thickness of approximately 60 feet. It is expected that the interval may exhibit similar porosity in the CFL area.

Additional information from core data is presented in Section B.8 in Tables B.8.7a and B.8.7b.

Trempealeau Porosity Range: Wireline data from the EDS #1-20 well was evaluated to assess Trempealeau porosity in this well location. Based on the neutron porosity, the Trempealeau Formation exhibits porosity ranging from 6-10% in cleaner zones with less shale admix. Additional information for the Trempealeau is presented in Section B.8.

E. Vertical and horizontal permeability of the injection zone and the method used to determine permeability. Horizontal and vertical variations in permeability expected within the area of influence.

Permeability data for the formations in the injection zone are provided in various tables in Section B.8.

F. The occurrence and extent of natural fractures and/or solution features within the area of influence.

No solution features such as paleokarst are documented in the proposed injection zone at the proposed well location. See B.8 for additional information about injection zone lithologies and structural geology.

G. Chemical and physical characteristics of the fluids contained in the injection zone and fluid saturations.

Fluid samples were obtained during drilling from the EDS Well No 2-12. These data indicate that the TDS concentrations in the Mt. Simon was 270,000 mg/L at this location; this is the closest Mt. Simon water quality data point to the CFL.

Additional information is provided in Sections B.7 and B.8.2.2.2.

H. The anticipated bottom hole temperature and pressure of the injection zone and whether these quantities have been affected by past fluid injection or withdrawal.

The nearest wells that penetrate through the Mt. Simon Sandstone that have well data including well logs are the EDS Wells #1-20, #1-12, and #2-12. Well log data for the EDS well #1-20 indicates the bottomhole temperature at a measure Log TD of 4,490 RKB was 100 degrees F.

Reservoir pressure in the Mt. Simon Sandstone is estimated based on data from the EDS Wells #1-12 and #2-12 as presented in the No Migration Variance Petition (Subsurface, 2000). The original measured pressure at the EDS #1-12 well was 1,825 psi at 4,000 ft RKB (reservoir pressure gradient of 0.4577 psi/ft); the extrapolated pressure at well #2-12 at 4,265 ft RKB was 1983.5 psi (0.4665 psi/ft). Averaging these two values results in a reservoir pressure gradient of 0.462 psi/ft, which is utilized for reservoir characterization at the CFL site in this document. This value is consistent with regional data for the Mt. Simon in this portion of Michigan. Based on an estimated total depth of 3,827 ft BGL at IW#1-36N and a reservoir pressure gradient of 0.462 psi/ft in the Mt. Simon, estimated bottom hole pressure is estimated to be 1768 psi; estimated bottom hole pressure at the IW#2-36E well location is estimated to be approximately 1,756 psi (estimated total depth of 3,802 ft BGL).

I. Formation fracture pressure, the method used to determine fracture pressure and the expected direction of fracture propagation.

Wells IW#1-36N and IW#2-36E will be designed for operation under positive pressure to be supplied by using an injection pump. Although no site specific data are available, two step-rate injection tests were conducted at the EDS #2-12 well on December 12 and 18, 2001. The results of the December 12 test indicated a fracture pressure gradient of 0.787 psi/ft. The test on December 18 indicated a fracture pressure gradient of 0.746 psi/ft. As a conservative approach, a fracture gradient of 0.74 psi/ft is assumed for calculations of maximum injection pressure.

Maximum wellhead injection pressure is calculated using the assumed formation fracture pressure and the specific gravity (SG) of the injectate. If a safety factor of 0.05 for the SG of the injectate (average SG expected to be between 1.00 to 1.06) is included, a maximum expected SG of 1.11 is assumed (1.06 + 0.05 = 1.11). Injection fluid is assumed to be comprised of this brine (SG = 1.11) that fills the tubing from the surface to the top of the injection zone. At IW#1-36N, this corresponds to a depth of 3,171 feet; at IW#2-36E this corresponds to a maximum depth of 3,141 feet. Maximum wellhead injection pressure at these two wells is calculated as follows (14.7 psi equals assumed atmospheric pressure):

- IW#1-36N: 3,171 ft * (0.74 psi/ft – (0.433 psi/ft * 1.11)) – 14.7 psi = 808 psi
- IW#2-36E: 3,141 ft * (0.74 psi/ft – (0.433 psi/ft * 1.11)) – 14.7 psi = 800 psi

These values are conservative since no allowances for tubing friction are included in this calculation. Average injection pressures are expected to be approximately 500 to 700 psi.

Note that the average specific gravity is expected to be in the 1.00 to 1.06 range. The maximum pressure exerted by injectate of a 1.06 specific gravity at the top of the injection zone (estimated to be 3,171 feet BGL [IW#1-36N] and 3,141 feet BGL [IW#2-36E]) is not likely to exceed 1,455 psi and 1,442 psi, respectively. Adding in the requested wellhead injection pressure for each well yields a total downhole pressure of 2,263 psi (IW#1-36N) and 2,242 psi (IW#2-36E), which is approximately 80 psi less than the calculated bottomhole fracture pressure of 2,347 psi at IW#1-36N (3,171 ft * 0.74 psi/ft) and 2,324 psi at IW#2-36E (3,141 ft * 0.74 psi/ft), which ignores friction losses, thus offering a conservative safety margin.

Note that CFL only intends to complete the two wells to the Franconia/Dresbach through the Mt. Simon Sandstone with a casing shoe at a depth of approximately 3,281 feet (IW#1-36N) and 3,251 feet (IW#1-36E). Therefore, calculations at the shallower depths of 3,171 and 3,141 feet, respectively, are conservative.

J. The vertical distance between the top of the injection zone from the base of the lowest fresh water strata.

As shown in the table above, the top of the Glenwood (top of the injection zone) is over 2,600 feet below the top of the Bass Islands. As CFL only intends to complete the wells to the top of the Franconia/Dresbach, the top of this interval is located almost 2,900 feet below the base of the USDW.

K. Other information the applicant believes will characterize the injection zone.

See Section B.8 for additional information.

B.11 Information to characterize the proposed confining zone, including:

A. The geological name of the stratum or strata making up the confining zone and the top and bottom depths of the confining zone.
B. An isopach map showing thickness and areal extent of the confining zone
C. Lithology, grain mineralogy and matrix cementing of the confining zone.
D. Effective porosity of the confining zone including the method of determination.
E. Vertical and horizontal permeability of the confining zone and the method used to determine permeability. Horizontal and vertical variations in permeability expected within the area of influence.
F. The occurrence and extent of natural fractures and/or solution features within the area of influence.
G. Chemical and physical characteristics of the fluids contained in the confining zone and fluid saturations.
H. Formation fracture pressure, the method used to determine fracture pressure and the expected direction of fracture propagation.
I. The vertical distance between the top of the confining zone from the base of the lowest fresh water strata.
J. Other information the applicant believes will characterize the confining zone.

Items A-C are detailed in Section B.8. Items D-J will be verified during drilling and testing of the IW-1 well. Literature data available to characterize formations has been cited in previous sections. Available data are summarized below.

A. The geological name of the stratum or strata making up the confining zone and the top and bottom depths of the confining zone.

The proposed confining zone is the Utica Shale, Trenton, and Black River Formations. The table below provides estimated top/bottom depths in feet below ground level (BGL) for these formations.

Estimated Formation Tops at the Proposed CFL Well Locations

Formation	Est. Depth to Top, from GL (ft)* IW#1-36N	Est. Depth to Top, from GL (ft)* IW#2-36E
Ground Level (feet ASL)	627	623
Base of Alluvium/Glacial Material	53	30
Lucas Formation (Detroit River Group)	53	30
Sylvania Sandstone	135	110
Bois Blanc	258	233
Bass Island Group	400	375
Salina Group	650	625
Niagara Group	1,122	1,097
Clinton Group	1,346	1,321
Undifferentiated Upper Cincinnatian	1,652	1,627
Utica Shale	2,227**	2,198**
Trenton Formation	2,357	2,323
Black River Formation	2,765	2,740
Glenwood	3,171	3,141
Trempealeau Formation	3,181	3,151
Franconia/Dresbach Formation	3,281	3,251
Eau Claire Formation	3,366	3,336
Mt. Simon Sandstone	3,527	3,502
Precambrian Granite Wash	3,807	3,782
Precambrian basement	3,827	3,802

*Estimated depth at proposed IW-1 location; IW-2 will likely be shallower. All depths shall be determined and finalized during well installation.

** Utica top based on regional map information. Note that often the top is picked higher up the column into the Upper Cincinnatian, resulting in a thicker Utica shale unit.

A. An isopach map showing thickness and areal extent of the confining zone

Figure B.8-15 is a regional isopach and Figure B.8-28 is a local isopach of the Utica Shale. Figure B-26 is a local isopach of the Trenton/Black River Formations. Based on these data, the estimated thickness of the Utica Shale and Trenton/Black River interval is at least approximately 900 feet and the interval is aerially extensive across the state.

B. Lithology, grain mineralogy and matrix cementing of the confining zone.

See Section B.8 for detailed lithologic information concerning the Confining Zone formation.

C. Effective porosity of the confining zone including the method of determination.

The Utica Shale is composed primarily of silty claystone deposited in a marine environment (Sattler, 2015). Western Michigan University (WMU,1981) reported porosity from cores collected and evaluated for the Consumers Power Company (Mirant Zeeland) Brine Disposal Well No 139 T4N, R15E, as being 1.5-4%. Sattler and Barnes (2018) noted that "The Utica Shale and Maquoketa Shale are considered to be the primary confining layers for Cambrian-Ordovician CO2 sequestration in the Midwest in the Michigan and Illinois Basins, respectively…" and "The Utica Shale is a notable confining zone in the region because of its widespread lateral continuity, dense mudrock lithology, and thickness in excess of 30 m." Sattler evaluated Utica porosity and permeability measurement data obtained from core obtained from wells in nearby Lenawee and Jackson county, which showed the Utica porosity to be between 0.77% and 2.78% based on core analysis, and permeability to be 0.003 mD-14.71 mD, nothing that the permeability data are horizontal, not vertical values.

The Black River/Trenton occurs immediately below the Utica Shale. Well log data at the EDS #1-20 well indicate that the average neutron porosity of the Trenton-Black River interval is generally 1-3%, noting that there may be more porous intervals. The Black River at EDS #1-20 exhibits a log porosity of approximately 2% throughout the entire interval, which is 454 feet thick (3,692-3,238 ft RKB). Regionally and where the Trenton-Black River is unfractured, porosity ranges from 2-5% and permeability of generally low (less than 10 mD, but lower than 0.01 mD) (Grammer, 2006).

D. Vertical and horizontal permeability of the confining zone and the method used to determine permeability. Horizontal and vertical variations in permeability expected within the area of influence.

As indicated under item B.11-D above, core data are available for the Utica Shale are available at various locations throughout the state (Briggs, 1968, Stattler, 2015). These data indicate that Utica Shale permeabilities of less than 0.5-2.5 md were reported for the "a location in southeastern Michigan" while Utica Shale permeabilities varied from 0.003-89.42 md elsewhere in the state. The Trenton Group at the Warner-Lambert Well No. 5 (T5N R15W Sec 20) was cored, and exhibited a horizontal brine permeability as low as 5.166×10^{-6} md and vertical core plug permeability to injectate as low as 5.2×10^{-6} md. Where unfractured and not an oil or gas reservoir as is likely the case at CFL, the Trenton and Black River likely exhibit similar permeabilities.

E. The occurrence and extent of natural fractures and/or solution features within the area of influence.

No solution features such as paleokarst are documented in the confining zone (i.e., Utica, Trenton/Black River) at the proposed well locations. See Section B.8 for additional information about confining zone lithologies and characteristics, as well as the occurrence of karst and solution features at the bedrock-alluvium/glacial clay contact.

The Trenton produces oil and gas elsewhere in southeastern Michigan in associated with known fault zones or structural trends (e.g. Cohee, 1945; Davies and Smith, 2006). Grammer (2006) concluded that structural mapping and log analysis of the Trenton/Black River suggest a close spatial relationship between dolomite and regional scale faulting, which is associated with major Trenton/Black River hydrocarbon producing fields like Albion/Scipio which occurs in Hillsdale, Jackson, and Calhoun counties, and Northville field that occurs in northwestern Wayne county. Geologic maps constructed at the top of the Trenton in the CFL area (Figure B-27) and Utica Shale (B-28) show no indication of structural features that would contribute to porosity development in the Trenton/Black River. It should be noted that even in areas where such features occur, the Utica Shale serves as a vertical cap for oil or gas migration.

F. Chemical and physical characteristics of the fluids contained in the confining zone and fluid saturations.

Data specific to the Utica Shale in the CFL area are not available. However, A search of the USGS Produced Waters Geochemical Database (USGS 2019) identified a water quality value for the Trenton Formation in Sumpter Township, corresponding to the well located in T4S R8E Section 22, which was abandoned in 1947. The Trenton Formation at this location yielded a water quality of 210,000 ppm TDS, indicating that the confining zone in the CFL area far exceeds 10,000 ppm TDS. Note that while no local Utica water quality data were identified, WMU (1981) states that the Utica Shale is not an aquifer, due to lower permeability and porosity, and water quality is likely comparable to that of the underlying Trenton/Black River.

G. Formation fracture pressure, the method used to determine fracture pressure and the expected direction of fracture propagation.

Wells IW#1-36N and IW#2-36E will be designed for operation under positive pressure to be supplied by using an injection pump. Although no site specific data are available, two step-rate injection tests were conducted at the EDS #2-12 well on December 12 and 18, 2001. The results of the December 12 test indicated a fracture pressure gradient of 0.787 psi/ft. The test on December 18 indicated a fracture pressure gradient of 0.746 psi/ft. As a conservative approach, a fracture gradient of 0.74 psi/ft is assumed for calculations of maximum injection pressure.

Maximum wellhead injection pressure is calculated using the assumed formation fracture pressure and the specific gravity (SG) of the injectate. If a safety factor of 0.05 for the SG of the injectate (average SG expected to be between 1.00 to 1.06) is included, a maximum expected SG of 1.11 is assumed (1.06 + 0.05 = 1.10). Injection fluid is assumed to be comprised of this brine (SG = 1.11) that fills the tubing from the surface to the top of the injection zone. At IW#1-36N, this corresponds to a depth of 3,171 feet; at IW#2-36E this corresponds to a maximum depth of 3,141 feet. Maximum wellhead injection pressure at these two wells is calculated as follows (14.7 psi equals assumed atmospheric pressure):

- IW#1-36N: 3,171 ft * (0.74 psi/ft – (0.433 psi/ft * 1.11)) – 14.7 psi = 808 psi
- IW#2-36E: 3,141 ft * (0.74 psi/ft – (0.433 psi/ft * 1.11)) – 14.7 psi = 800 psi

These values are conservative since no allowances for tubing friction are included in this calculation. Average injection pressures are expected to be approximately 500 to 700 psi.

Note that the average specific gravity is expected to be in the 1.00 to 1.06 range. The maximum pressure exerted by injectate of a 1.06 specific gravity at the top of the injection zone (estimated to be 3,171 feet BGL [IW#1-36N] and 3,141 feet BGL [IW#2-36E]) is not likely to exceed 1,455 psi and 1,442 psi, respectively. Adding in the requested wellhead injection pressure for each well yields a total downhole pressure of 2,263 psi (IW#1-36N) and 2,242 psi (IW#2-36E), which is approximately 80 psi less than the calculated bottomhole fracture pressure of 2,347 psi at IW#1-36N (3,171 ft * 0.74 psi/ft) and 2,324 psi at IW#2-36E (3,141 ft * 0.74 psi/ft), which ignores friction losses, thus offering a conservative safety margin.

Note that CFL only intends to complete the two wells to the Franconia/Dresbach through the Mt. Simon Sandstone with a casing shoe at a depth of approximately 3,281 feet (IW#1-36N) and 3,251 feet (IW#1-36E). Therefore, calculations at the shallower depths of 3,171 and 3,141 feet, respectively, are conservative.

H. The vertical distance between the top of the confining zone from the base of the lowest fresh water strata.

As shown in the table above, the top of the Utica Shale (top of the confining zone) is over 1,800 feet below the base of the Bois Blanc, which is conservatively assigned as the lowermost USDW in the CFL area.

J. Other information the applicant believes will characterize the confining zone.

See Section B.8 for additional information.

REFERENCES

Cohee, George V, 1945. “Geology and Oil and Gas Possibilities of Trenton and Black River Limestones of the Michigan Basin, Michigan and Adjacent Areas. USGS Oil and Gas Investigations Preliminary Chart 11

Davies, Graham R. and Langorne B. Smith Jr. “Structurally controlled hydrothermal dolomite reservoir facies: An overview.” AAPG Bulletin, V. 90, no. 11 (November 2006), pp. 1641–1690.

Grammer, Michael G., 2006, Phase II (Year 2) Summary of Research – Establishing the Relationship Between Fracture-Related Dolomite and Primary Rock Fabric on Distribution of Reservoirs in the Michigan Basin, Department of Energy Topical Report DE-FC26-04NT15513.

B.12 Information demonstrating injection of liquids into the proposed zone will not exceed the fracture pressure gradient and information showing injection into the proposed geological strata will not initiate fractures through the confining zone. Information showing the anticipated dispersion, diffusion and/or displacement of injected fluids and behavior of transient pressure gradients in the injection zone during and following injection.

Maximum Injection Pressure

Wells IW#1-36N and IW#2-36E will be designed for operation under positive pressure to be supplied by using an injection pump. Although no site specific data are available, two step-rate injection tests were conducted at the EDS #2-12 well on December 12 and 18, 2001. The results of the December 12 test indicated a fracture pressure gradient of 0.787 psi/ft. The test on December 18 indicated a fracture pressure gradient of 0.746 psi/ft. As a conservative approach, a fracture gradient of 0.74 psi/ft is assumed for calculations of maximum injection pressure.

Maximum wellhead injection pressure is calculated using the assumed formation fracture pressure and the specific gravity (SG) of the injectate. If a safety factor of 0.05 for the SG of the injectate (average SG expected to be between 1.00 to 1.06) is included, a maximum expected SG of 1.11 is assumed (1.06 + 0.05 = 1.11). Injection fluid is assumed to be comprised of this brine (SG = 1.11) that fills the tubing from the surface to the top of the injection zone. At IW#1-36N, this corresponds to a depth of 3,171 feet; at IW#2-36E this corresponds to a maximum depth of 3,141 feet. Maximum wellhead injection pressure at these two wells is calculated as follows (14.7 psi equals assumed atmospheric pressure):

- IW#1-36N: 3,171 ft * (0.74 psi/ft – (0.433 psi/ft * 1.11)) – 14.7 psi = 808 psi
- IW#2-36E: 3,141 ft * (0.74 psi/ft – (0.433 psi/ft * 1.11)) – 14.7 psi = 800 psi

These values are conservative since no allowances for tubing friction are included in this calculation. Average injection pressures are expected to be approximately 500 to 700 psi.

Note that the average specific gravity is expected to be in the 1.00 to 1.06 range. The maximum pressure exerted by injectate of a 1.06 specific gravity at the top of the injection zone (estimated to be 3,171 feet BGL [IW#1-36N] and 3,141 feet BGL [IW#2-36E]) is not likely to exceed 1,455 psi and 1,442 psi, respectively. Adding in the requested wellhead injection pressure for each well yields a total downhole pressure of 2,263 psi (IW#1-36N) and 2,242 psi (IW#2-36E), which is approximately 80 psi less than the calculated bottomhole fracture pressure of 2,347 psi at IW#1-36N (3,171 ft * 0.74 psi/ft) and 2,324 psi at IW#2-36E (3,141 ft * 0.74 psi/ft), which ignores friction losses, thus offering a conservative safety margin.

Note that CFL only intends to complete the two wells to the Franconia/Dresbach through the Mt. Simon Sandstone with a casing shoe at a depth of approximately 3,281 feet (IW#1-36N) and 3,251 feet (IW#1-36E). Therefore, calculations at the shallower depths of 3,171 and 3,141 feet, respectively, are conservative.

Average Rates, Volumes and Pressures

The range of injection rates and pressures is expected to fluctuate depending on the demands of the system along with variables related to the well and reservoir conditions. Operational injection rates are expected to average approximately 70 gpm per well (combined average from two wells of 140 gpm), with a maximum rate of 80 gpm per well, for a combined maximum injection rate of 160 gpm. The estimated annual volume is not expected to exceed 84,096,000 gallons/year, with an average daily volume of 201,600 gallons (140 gpm) and maximum expected daily volume of 230,400 gallons (160 gpm). Table B.12-1 presents representative historic leachate generation information that reflects anticipated injectate volumes.

Table B.12-1. Annual Leachate Volumes, Carleton Farms Landfill, 2014-2019

Year	Volume (gallons)
2014	19,188,796
2015	20,270,182
2016	30,385,240
2017	35,949,955
2018	62,181,290
2019*	36,553,412 / 72,000,000

* 2019 volumes from data thru July; 72,000,000 annual volume is projected estimate for the year.

The wells are to be operated, and operating data will be reported, according to the requirements presented in Table B.12-2.

Table B12-2. Operating, Monitoring, and Reporting Requirements, CFL IW#1-36N and IW#2-36E

Characteristic	Value	Minimum Monitoring Frequency [2]	Minimum Reporting Frequency
Injection Rate (Maximum); Per Well	80 gallons/min	Continuous	Monthly
Injection Rate (Maximum); Combined	160 gallons/min	Continuous	Monthly
Injection Rate (Average); Per Well	70 gallons/min	Continuous	Monthly
Injection Rate (Average); Combined	140 gallons/min	Continuous	Monthly
Cumulative Estimated Annual Volume, Both Wells	73,584,000 gallons/year	Continuous	Monthly
Injection Pressure (maximum); IW#1-36N	822 psig	Continuous	Monthly

Injection Pressure (maximum); IW#2-36E	814 psig	Continuous	Monthly
Injection Pressure (average); both wells	500 - 700 psig	Continuous	Monthly
Annulus Pressure	100 psig min.	Continuous	Monthly
Annulus/Tubing Pressure Differential	100 psig min.	Continuous	Monthly
Sight Glass Level	Visible	Daily, when operated	Monthly
Annulus Fluid Addition Or Removal	None	Monthly	Monthly
Chemical Composition of Injected Fluids[1]	None	Monthly	Monthly
Physical Characteristics of Injected Fluids[1]	Non-hazardous	Monthly	Monthly

[1] As specified in the Waste Analysis Plan, see Attachment C (CD-ROM)
[2] Continuous is to be defined as a value recorded not less than once every five (5) minutes

Impact of Injection

There are five wells that penetrate into the confining zone, but none of these wells was drilled through the base of the confining zone into the uppermost injection zone within the two-mile AOR. The nearest wells that penetrate the injection zone and injection interval are the two Class I non-hazardous wells at the EDS facility, located approximately 11 miles northeast of the CFL facility.

The Franconia/Dresbach through Mt. Simon injection interval will be tested to verify capacity upon well installation. Until data are obtained during installation of the well, estimates of formation properties have been assigned based on regional data associated with the closest wells to the Mt. Simon being the EDS wells in Romulus, MI (Wells #1-12 [UIC Permit MI-163-1W-C010], #2-12 [UIC Permit MI-163-1W-C011], and #1-20 [plugged and abandoned; previous UIC Permit MI-163-1W-006]) and projected operational parameters, to generate an estimate of the fluid front for the two proposed CFL wells. Standard equations for the volume of a porous cylinder can be used with the following parameters to generate an estimate for a simplistic piston-like displacement fluid front radius. Based on parameters determined at the EDS wells, the following conservative formation characteristics and injectate volumes were assumed:

- 210 foot net thickness in the injection interval, which is estimated to have a gross thickness of approximately 650 feet at both wells
- 840,960,000 gallons of injectate at each well, estimated based on twenty years of continuous injection at a rate of 42,048,000 gallons per year (80 gpm)

The following formula was used to estimate the radius of fluid displacement at each well:

$$\text{Radius} = (\text{volume} / \pi * \Phi * h)^{1/2}$$
$$= [(840{,}960{,}000 \text{ gal} * \text{ft}^3/7.48 \text{ gal}) / \pi * 0.11 * 210]^{1/2}$$
$$= 1{,}245 \text{ ft}$$

As an estimate for illustrative purposes, this calculation yields a piston-like, 100 percent injected fluid front radial distance of approximately 1,245 feet from each well (see Figure B.6-3). Although dispersion will play a role in spreading this plume over a slightly larger area, even a relatively large dispersivity combined with a low cut-off boundary concentration would likely yield a plume that reaches a radial distance of just under ¼-mile from the well. This is much smaller than the two-mile AOR radius for which artificial penetrations were identified and evaluated.

Compatibility problems encountered due to injection of non-hazardous landfill leachate and gas condensate are possible due to injection of particulate matter that could cause decreased flow capacity. Screens or filters may be used to condition fluids if needed. Due to the composition of the fluid to be injected and landfill origin, periodic biocide treatments may be instituted as needed to prevent the establishment of bacterial plugging issues. Also, it is possible that the concentration of iron within injectate could lead to precipitation issues within tubing, pipe, or the formation, so implementation of a system to prevent plugging or treat iron may be required. Such solids, compatibility, or bacterial problems, if they do occur, would not be a containment issue, but would be an operations issue. If plugging occurred and was not remedied, the operator could reduce injection rates so that maximum pressure limits are not exceeded. To sustain rates if such a situation develops, periodic stimulations may be required, but would be accomplished within regulatory requirements.

B.13 Proposed operating data including all of the following data:
A. The anticipated daily injection rates and pressures.
B. The types of fluids to be injected.
C. A plan for conducting mechanical integrity tests.

A and B. As noted in Section B.12, continuous injection at an average rate of 70 gpm per well (140 gpm combined; equivalent to 201,600 gallons per day) is projected. This is equivalent to an injection volume from two wells of approximately 73,584,000 gallons per year. At the maxiumum permitted injection rate of 160 gpm (80 gpm per well), injection volume is equivalent to not more than 80,096,000 gallons per year. As noted on Table B.12-2, average injection pressure is estimated to be approximately 500 to 700 psig with a maximum injection pressure of not more than 822 psig at IW#1-36N and 814 psig at IW#2-36E. The injectate will be non-hazardous fluids generated on-site from landfill leachate and gas condensate collection systems. As necessary, storm water, surface water run-off, and/or fluids derived from or necessary for disposal well operation and maintenance may also be injected. See Item B.9 and B.12 for additional information pertaining to daily injection rates/pressure and the types of fluids to be injected.

C. Annual Part I mechanical integrity testing for IW#1-36N and IW#2-36N will include reservoir monitoring as specified by permit requirements in addition to static annulus pressure testing. CFL will provide the agency a minimum of 30 days notice prior to annual testing. Although test procedures or methods may be changed based on approval by EGLE staff, the following procedure will be used for the first such testing performed:

1. Conduct Wellsite Safety Meeting
    a. Prior to commencement of field activities, conduct safety meeting with contractors and personnel to be involved with field services and MIT testing. Ensure that all safety procedures are understood and review days' work activities.
2. Conduct Reservoir (Fall-Off or Static) Pressure Test
    a. For fall-off, record data regarding test well injection at typical operating conditions (constant rate). Rate versus time data will be recorded during the injection period. Cumulative injection volume will also be recorded. Continue injection for a minimum of approximately 8 hours. Note that significant rate variations may yield poor quality data or require more complicated analysis techniques.
    b. Rig-up pressure gauge and run in well to a depth likely not to exceed approximately 3,300 feet or other depth approved by EGLE.
    c. For pressure transient fall-off, obtain final stabilized injection pressure for a minimum of 1 hour. For static test, collect a minimum of two pressure/temperature readings at depth. Ensure that the gauge temperature readings have also stabilized.
    d. After gauge recordings are stable, cease injection and monitor pressure fall-off. Continue monitoring pressure for a minimum of 8 hours or until a

valid observation of fall-off curve is observed. For a static gradient survey, the well will be shut-in for a minimum of 48 hours before testing. Wellbore pressure gradients will be obtained to establish fluid gradient and bottomhole pressure data will be collected for a minimum of 4 hours for static testing.

   e. Stop test data acquisition, rig-down and release equipment.

3. Annulus Pressure Test
   a. Stabilize well pressure and temperature.
   b. As practical, arrangements will be made for a representative from EGLE to be present to witness testing.
   c. Install ball valve or similar type "bleed" valve on annulus gate valve. Pressurize annulus to a minimum of 100 psig above maximum permitted operating pressure and shut-in valve. Install certified gauge on "bleed" type valve. The annulus may need to be pressurized and bled off several times to ensure an absence of air.
   d. Monitor and record pressure for 1 hour. Pressure may not fluctuate more than 3% during the one-hour test.
   e. Lower the annulus pressure to normal operating pressure at the end of the test.

Part II mechanical integrity testing to be conducted every 5 years, as required by EGLE, is detailed in Sections A.11 and A.14 and is not repeated herein.

B.14 For a proposed disposal well to dispose of waste products into a zone that would likely constitute a producing oil or gas pool or natural brine pool, a list of all offset operators and certification that the person making application for a well has notified all offset operators of the person's intention by certified mail. If within 21 days after the mailing date an offset operator files a substantive objection with the supervisor, then the application shall not be granted without a hearing pursuant to part 12 of these rules. A hearing may also be scheduled by the supervisor to determine the need or desirability of granting permission for the proposed well.

Production from the Franconia/Dresbach through the Mt. Simon interval has not been identified in the vicinity of the proposed disposal well. There are also no deep wells within the vicinity of the CFL that penetrate to or produce from zones below the Black River Formation, which is the lowermost interval of proposed upper confining zone. Therefore, a list of offset operators is not required.

B.15 A proposed plugging and abandonment plan

The following is the proposed plan for plugging and abandonment of the proposed IW#1-36N and IW#2-36N wells. Note that procedures for plugging will be the same for both wells, though there is minor variations in depths and cement volumes based on minor differences in projected depths.

<u>CFL IW#1-36N and IW#2-36E PLUGGING AND ABANDONMENT PLAN</u>

1. Notify regulatory agencies a minimum of 30 days prior to commencement of plugging operations.
2. Prepare well and location for plugging. Move in and rig up well servicing rig, pipe racks and tanks.
3. Install a test gauge on the annulus to perform a static annulus pressure test. Ensure that the annulus is fluid filled and that the well has been shut-in for a minimum of 24 hours. Pressurize annulus and isolate from the annulus system. Monitor annular pressure for one hour.
4. Displace tubing with kill brine as needed to control wellhead pressure. Dismantle wellhead and install blow-out preventer. Displace annulus with kill brine as needed to control pressure. Brine compatibility with cement to be used will be verified.
5. Remove injection tubing and packer. If packer will not unseat, proceed with fishing operations as needed to remove packer from hole or obtain approval to set retainer above packer and pump cement through retainer and abandoned packer.
6. Make up mechanical retainer on workstring and trip in hole. Set cement retainer at top of injection interval just above historical packer setting depth. Test cement retainer to 500 psig.
7. Move in cement and cementing equipment.
8. Displace hole below retainer with Class “A” cement. Unsting from retainer and spot 50 additional sacks (sx) on top of retainer. Cement volume has been calculated based on the following volumes for IW#1-36N and IW#2-36E:

   <u>IW#1-36N</u>
   - 6-1/8” hole from 3,281 ft BGL to a projected depth of 3,827 ft BGL, at 0.2046 ft^3/ft = 112 ft^3, or 95 sx Class “A” cement
   - 7” casing from surface to 3,281 ft GL, at 0.2148 ft^3/ft = 705 ft^3, or 597 sx Class “A” cement

   <u>IW#2-36E</u>
   - 6-1/8” hole from 3,251 ft BGL to a projected depth of 3,802 ft BGL, at 0.2046 ft^3/ft = 107 ft^3, or 90 sx Class “A” cement
   - 7” casing from surface to 3,251ft GL, at 0.2148 ft^3/ft = 698 ft^3, or 592 sx Class “A” cement

Therefore, the total volume of the plugs is estimated to be 817 ft^3, which is equivalent to 692 sx of Class “A” cement with a yield of 1.18 ft^3/sack for IW#1-36N. For IW#2-36E, the total volume is estimated to be 805 ft^3, which is equivalent to 682 sx of Class “A” cement with a yield of 1.18 ft^3/sack. If wellbore fill is present, this volume may have to be reduced or squeezed into the openhole of the injection interval.

9. Once cement has been tagged on top of the retainer, spot successive, continuous balanced cement plugs in 500’ intervals from top of cement retainer to surface (6 intervals required). Cement to be API Class ‘A’ with not more than 4% bentonite. If neat Class ‘A’ cement is pumped it will have the following slurry properties.
    - Water ratio – 5.2 gallons per sack
    - Slurry weight – 15.60 pounds per gallon
    - Slurry volume – 1.18 ft^3/sack

    An estimated 547 sacks, or 645 ft^3, of slurry will be required above the retainer for IW#1-36N; for IW#2-36E, an estimated 542 sacks, or 640 ft^3, will be required.
10. Remove BOP and wellhead equipment.
11. Cut off wellhead approximately 4 feet BGL and weld cap with permanent marker on casing.
12. Rig down and move out all equipment.
13. Prepare and file USEPA and EGLE Plugging Reports.

The steel plate will be inscribed with the disposal well identification information and the date of plugging. Federal and State representatives will have been invited to witness the plugging and sign the plug and abandonment form.

B.16 Identify the source or sources of proposed injected fluids. Identify if injected fluids will be considered hazardous or non-hazardous as defined by Part 111, Hazardous Waste Management, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended (NREPA)

See Section B.9 for information about waste sources and waste chemistry. As stated in Section B.9, non-hazardous landfill leachate and gas condensate will be injected in the proposed IW#1-36N and IW#2-36E injection wells. Injection of fluids generated on-site will provide an environmentally safe management option that does not require off-site transport with associated traffic, potential for fluid spillage, and other issues. CFL believes Class I authorization will provide the most environmentally safe option for management of on-site generated fluids into formations deeply isolated from overlying USDWs. This will safely, cost effectively, and efficiently manage non-hazardous fluids via injection while minimizing the risks associated with transporting such wastes substantial distances to utilize other fluid management methods.

B.17 Whether the well is to be a multisource commercial hazardous waste disposal well.

This well permit application request is for single source non-hazardous wells, not multisource commercial hazardous waste disposal wells.

B.18 Additional information required for an application for a permit to drill and operate a storage well or to convert a previously drilled well to such a well:

For an application to drill storage well or to convert a previously drilled well to a storage well, also submit the following information in addition to that submitted in the previous section for a disposal well. In the previous sections instructions, replace the term ‘disposal’ with ‘storage’ and ‘waste’ with ‘stored product.’

1. **The name and chemical formula of the product to be stored, and a characterization of the physical, chemical, and hazardous or toxic properties of the product.**
2. **The anticipated vertical and horizontal dimensions and volume of the completed underground storage cavity.**
3. **The anticipated operating life of the underground storage cavity.**
4. **The method to be used to create the underground storage cavity.**
5. **The name of the geological stratum in which the underground storage cavity will be created.**
6. **A schematic diagram of the well bore showing the proposed arrangement and specifications of the down hole well equipment.**
7. **If the underground storage cavity is to be formed by solution mining bedded salt, then all of the following information shall be included:**
8. **The plan for disposal of brine produced during solution mining of the underground storage cavity and for the operating life of the underground storage cavity.**
9. **The expected starting and ending dates of the solution mining.**
10. **The range of anticipated operating pressures of the underground storage cavity.**
11. **The anticipated range of operating injection pressure.**
12. **The proposed method of displacing stored product.**
13. **A plan for testing the mechanical integrity of the underground storage cavity as provided in R 299.2392 and R 299.2393.**

N/A. This application is not being submitted for a permit to drill and operate a storage well or to convert a previously drilled well to such a well.

Petrotek

B.19 Additional information required for an application for a permit to drill and operate a well for the production of artificial brine or to convert a previously drilled well to such a well:

For an application to drill and operate a brine well for production of artificial brine or to convert a previously drilled well to a well for production of artificial brine, submit in addition to the information in the first section, all of the following proposed information:

1. **If the well will be drilled into an existing cavern, the number of wells in the cavern, the present extent of the cavern, and the purpose of the proposed well.**
2. **The name of the geological stratum or strata to be mined, the top and bottom depths of the mined zone, the gross and net mineable thickness, and the mineral or minerals to be recovered by solution mining.**
3. **An isopach map showing thickness and areal extent of the strata to be mined.**
4. **A sketch showing the extent of the planned mine area.**
5. **The geological strata to be left in place for roof support.**
6. **A diagram showing the well bore with the proposed casing program and its relationship to the stratum or strata to be mined.**
7. **A plan for conducting subsidence monitoring as required in R 299.2407 or a rationale for not conducting subsidence monitoring.**

N/A. This application is not being submitted for a permit to drill and operate a well for the production of artificial brine or to convert a previously drilled well to such a well.

A public hearing may be scheduled by the Supervisor of Mineral Wells to take public comment on the proposed well. If such a hearing is scheduled, the applicant will be responsible for the scheduling and preparation and publication of the notice.

Please collate the above documents into a set and mail the original and two copies of the application (total of 3 sets) plus 3 additional copies of form EQP 7200-1 to:

Department of Environment, Great Lakes and Energy
Office of Geological Survey
P.O. Box 30256
Lansing, Michigan 48909

The above documents have been collated and appropriate numbers of document and form copies have been sent to the above address.